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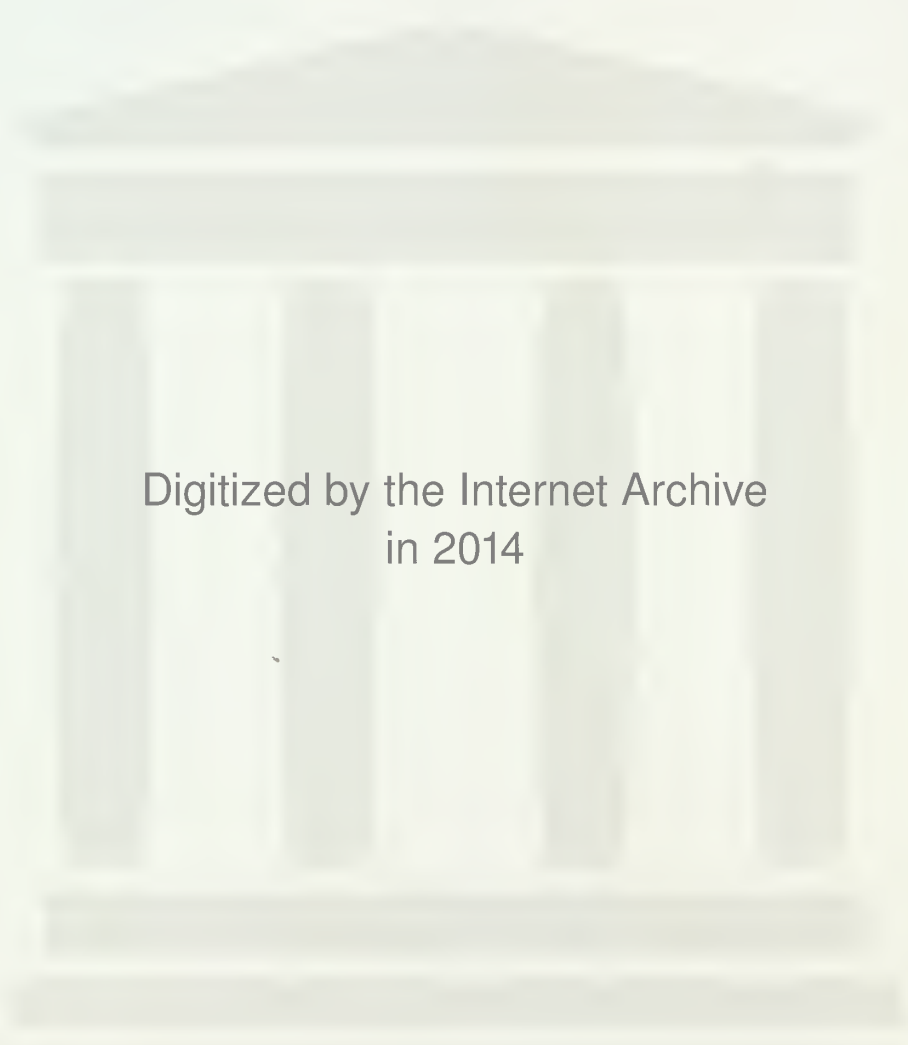
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FEASIBILITY OF A 15 MW WOOD-FIRED AND GEOTHERMAL POWER PLANT

FINAL REPORT

Prepared for

Montana Department of Natural Resources
and Conservation

by

GeoProducts Corporation

August 6, 1986

(Grant Agreement #DE-FG79-82BP35776)

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A. EXECUTIVE SUMMARY

1. Introduction

This report assesses the feasibility of developing a 15-megawatt (MW) power plant near Ennis in Madison County, Montana. Moderate-temperature geothermal resources near the town of Ennis might be used economically in the development and operation of a 15 Mw power station near Ennis. The power from the project would be sold to one of the utility companies operating in Montana at purchase rates provided by the company and authorized by the Montana Public Service Commission (PSC).

2. Wood Fuel Availability and Costs

A wood fuel procurement area with a nominal 60 mile radius of Ennis was studied to determine potential fuel inventories, sources, and cost of fuel delivered to the project site. Wood fuel requirements for the several power cycles analyzed ranged from 160 - 220 tons per day oven dried (OD). All potential fuel sources and competing markets for the fuel were identified.

The study found there to be an annual gross volume of 25,676 OD tons of forest residue and 134,435 OD tons of mill residue that could be generated in the study area. The estimated cost of wood fuel delivered to the Ennis site ranged from \$47

- \$56 per OD ton for forest residue and from \$13 - \$24 per OD ton for delivered mill residue.

In the absence of a fuel procurement strategy that involved actual stumpage purchases it is estimated that the project could realistically expect to obtain no more than 32,000 OD tons annually of the approximately 160,000 OD tons of forest and mill residue available.

3. Geothermal Resource Assessment

Regional geophysical studies in the Madison Valley indicate a basin depth of about 6,000 to 7,000 feet near Ennis with complex faulting along NW and NE to E trends in the Hot Springs area. The north trending Madison fault along the east side of the valley is the most prominent structural feature and has been associated with considerable historic seismic activity. The Ennis Hot Springs, with the highest surface discharge temperature in the state are situated about 2 miles east of the Tobacco Root range front on the west side of the valley.

Temperature data were obtained from a number of drill holes ranging from 30 to 1,200 feet in depth. Some of the gradient profiles show a temperature reversal which may be indicative of lateral recharge of the main production zone in the well from a connected vertical conduit. This is consistent with a model of thermal fluids rising along steep intravalley faults and moving out and mixing into near surface alluvial aquifers

or along the alluvial/bedrock contact. The high thermal gradients in several wells were used to estimate a circulation depth of about 2 km which is roughly the base of the valley fill section east of Ennis. The heat source for the system is probably the above average heat flow of the region as opposed to a magmatic source.

The subsurface temperature that might be accessed at a depth of 1.5 km (~ 5000 feet) below the Ennis Hot Springs is estimated to be about 135°C (275°F). The ability of the system to sustain yields on the order of 1,000 to 2,000 gpm without excessive pumping lifts can not be determined at present. Future drilling should be targeted on the main (and presumably most permeable) structures in and around the Hot Springs. Drill holes should aim at penetrating these upflow zones deeper in the section for higher temperatures, which will probably necessitate stepping to the east or northeast. Prior to siting an exploratory well some additional consideration of the structure east of the Springs might be warranted. After this review, a 2,000 to 3,000 foot thermal gradient or slim hole would allow a testing of the structural and heat flow models at limited risk.

4. Conceptual Engineering

- a. Power Cycles. Three power cycles were studied, two of which incorporated different geothermal resource tem-

peratures. The base cycle was a conventional wood-fired steam turbine configuration. The second incorporated geothermal energy in feedwater and combustion air pre-heating applications. The third cycle incorporated a geothermal binary fluid loop with a separate turbine generator. Output from each cycle was 15 MW.

- b. Performance Gains From Geothermal Energy. Incorporating geothermal energy into boiler feedwater heating requirements results in a net wood fuel savings of about 6,000 - 19,000 OD tons/year, depending on the geothermal resource temperature. In terms of total wood fuel requirements, this savings ranges from about 2% to 7%. The savings in wood fuel requirements ranges from about 4½% - 8% when the geothermal is used in combustion air heating. When both uses are combined, the savings is between 15 - 17%, depending on a temperature range of 250 - 275°F.

When the geothermal energy is used in a parallel binary power cycle (net cycle efficiency estimated to be about 15%) the wood fuel savings is about 27 - 30%, depending on a geothermal source temperature of 250 or 275°F. The total wood fuel requirement for the wood only cycle is 10.8 tons/hour or about 80,000 tons/year (OD, at 85% CF).

- c. Pollution Control. Principal air pollution control equipment would include a multi-cyclone particulate

separator and a 2-stage wet gas scrubber which is preferred over the electrostatic precipitator. Based on information supplied by equipment vendors, particulate air emissions from the base case wood only plant are estimated to be 24 lbs. per hour. Emissions from hog fuel boilers are predominately particulates. Wood fuel contains little or no sulfur, and other gaseous emissions including NO_x would be within EPA guidelines.

- d. Capital Costs. Capital costs range from \$12.2 million for the base wood only plant to \$24.6 million for the geothermal binary cycle/wood cycle plant. An allowance for working capital, project development and transmission line increase these costs to \$14.9 million and \$28.7 respectively. Including allowances, the plant cycle incorporating geothermal air and feedwater heating is estimated at about \$16.1 million.

5. Marketing and Sales

At the time this feasibility investigation began, it was believed that project power could be sold economically to the Montana Power Company at the then prevailing rates (about 6.3¢/kwh) and at an attractive escalation rate to be set by the Public Service Commission. To the contrary, at public rate hearings held since then, the PSC has consented to a drastic reduction in power rates that the utility companies serving Montana must pay to small power producers.

This rate reduction has made the proposed project not economically feasible for the foreseeable future. Wheeling the power to utility companies serving other areas is not economically feasible. Rural cooperatives and the Bonneville Power Administration (BPA) do not offer sufficiently high power sales rates to economically justify most small power projects.

Except for certain cogeneration and hydroelectric projects, Qualifying Facilities (QF) power cannot be marketed economically in Montana at the present time. The picture may change several years in the future as the current power surplus in the northwest disappears and utility companies develop more geographically diverse marketing strategies.

6. Economic Analysis

Based on the data assembled in the engineering, marketing, wood fuel and geothermal assessment task a comprehensive economic model was formulated to determine the relative profitability of the proposed project.

This model examined over time the profitability of each cycle and the sensitivity of the rate of return to changes in various factors, including wood fuel cost, geothermal temperature, capacity factor and power sales revenue.

For reasons already mentioned, mainly the low rates offered small power producers by MPC, none of the cycles can be eco-

nomically justified at this time. The internal rate of return (IRR) and the net present value (NPV) of each cycle are as follows:

	<u>IRR</u>	<u>NPV (20% d.f.)</u>
Cycle I	- .42%	(\$10,420) *
Cycle II-A	1.72%	(\$10,313)
Cycle III-A	.67%	(\$18,347)

* Thousands of Dollars

7. Environmental Planning

The environmental problems associated with this or a similar project are quite manageable. Because of the chemistry of wood fuel, the only potential air quality problem would be particulate emissions. The staged stack cleanup systems noted in (4) above would ensure project compliance with state and federal air emissions standards.

Fly and bottom ash would be collected at the rate of about 4 tons/day at the maximum wood fuel consumption rate for the base case cycle plant. Disposal would have to be in a properly designated landfill or, preferably, in a market for agricultural chemicals.

Plant liquid wastes including treated sewage effluent would be collected in a lined evaporation pond about 2 acres in area and 4 feet deep. This pond would handle all liquid waste streams except the effluent geothermal fluid. This stream may be accommodated by surface disposal, if its chemistry permits, or by injection if required for environmental reasons or for reasons of pressure maintenance in the producing geologic formations.

B. WOOD FUEL PROCUREMENT

1. Fuel Availability

A wood fuel procurement area with a nominal 60 mile radius from Ennis was studied to determine potential fuel inventories, sources, and costs of fuel volumes delivered to the project site. A majority of the forested areas, consisting largely of Lodgepole Pine and Douglas-fir species, is comprised of mature and overmature timber, suggesting the beneficial effects that would accrue to forest management efforts from improved utilization, commercial thinnings, and the removal of dead material.

The specific areas evaluated included the Tobacco Root and Pioneer mountains as well as the Gravelly and Madison Ranges (Figure 1). Although these areas have large acreages of forested lands, they do not produce the volume of wood fiber or quality of commercial trees found on the west side of the Continental Divide where soils are deeper and precipitation is more abundant.

Due to the high estimated costs of delivered fuel from pre-commercial thinning operations [up to \$150 per OD (oven dry) ton] and the relatively low volumes of non-commercial tree species (cottonwood, aspen and juniper as well as their greater value for wildlife and other environmental values), the analysis was based on the availability of fuel only from forest and logging residues and mill residual material.

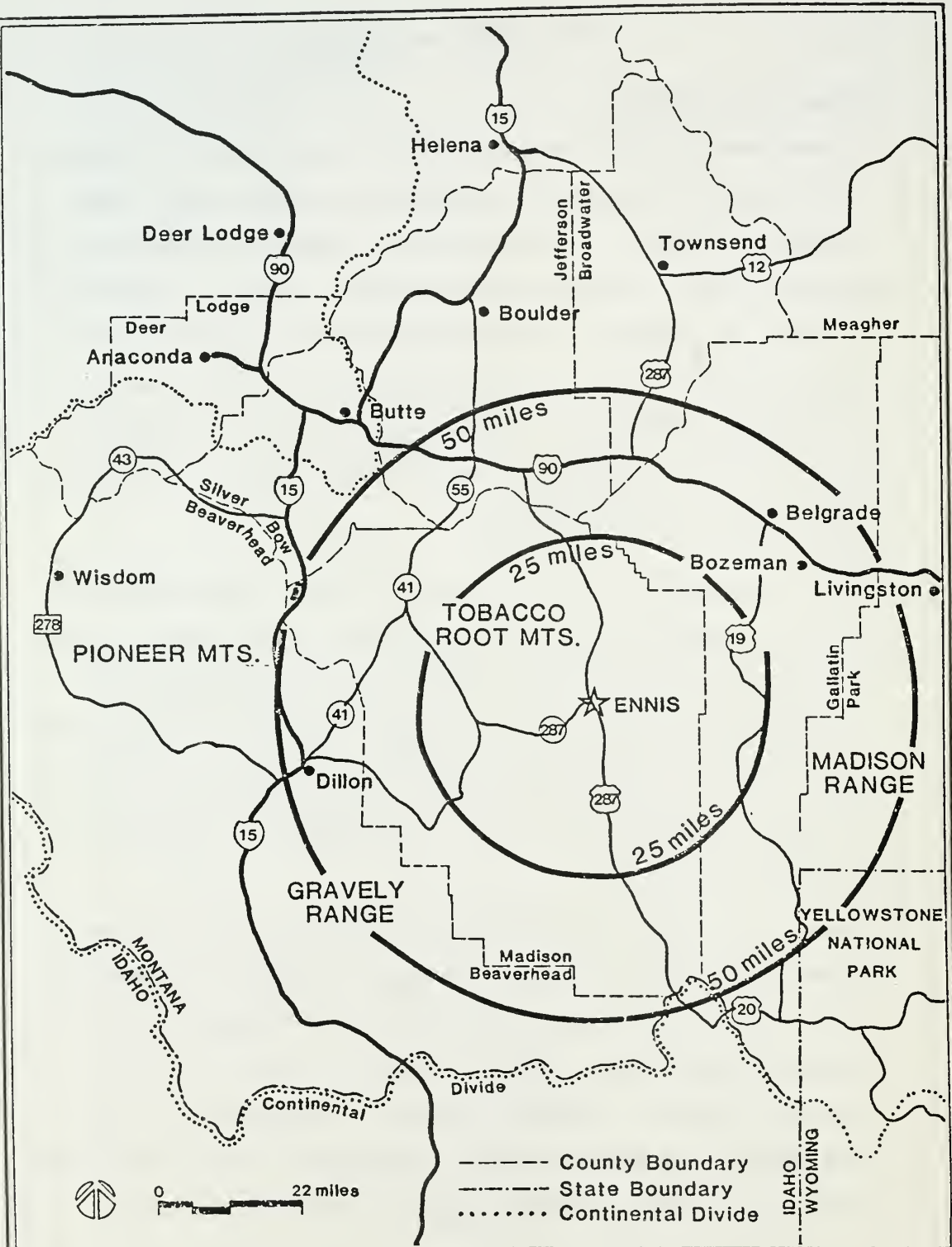


FIGURE 1. LOCATION MAP

The study found there to be an annual gross volume of 25,676 OD tons of forest residue and 134,435 OD tons of mill residue that could be generated in the study area. A small portion of the forest residue is currently utilized as local fuel sources. A majority of the mill residue is utilized and the demand for this material will only increase in the future, particularly as the concept of cogeneration and locally generated electric power gains in popularity.

A procurement strategy based on stumpage purchases might be required to ensure the availability of fuel required for the project. While there would be initial opposition to such a strategy, if the project could demonstrate that there would be no increase in log costs to local mills and quality log manufacturing, the strategy would gain in acceptance, as has occurred in other areas of the west. In the absence of such a stumpage procurement strategy, it is estimated that the project could realistically expect to obtain no more than 32,000 OD tons annually of the approximately 160,000 OD tons of forest and mill residue available. Tables I and II summarize the source and volume of this gross residue.

2. Fuel Costs

The cost of wood fuel delivered to the Ennis project site ranged from \$47-56 per OD ton for forest residue and from \$13-24 per OD ton for delivered mill residue. The range

TABLE I

VOLUME OF FOREST RESIDUE - PRODUCED ANNUALLY
(OVEN DRY TONS)

(1) Region	(2) Land Ownership	(3) Annual ^a Harvest MBM Scrib.Dec.C.	(4) Cunits ^b	(5) Oven ^c Dry Ton	(6) By Species ^d (O.D.T.)	(7) Gross Volume ^e of Residue + Volume of Green Timber Harvested	(8) Gross Volume of Residue + Residue (6)x(7)	(9) Net (f) Volume of Residue + Gross Volume of Residue	(10) Net Volume of Logging Residue (8)x(9)
Tobacco Root	U.S. Forest Service Private Land	1.0	2,353	2,838	LPP 2,128 DF 710	0.42 0.21	894 149	.73 .63	652 94
Madison	U.S. Forest Service Private Land	12.2	28,706	34,619	LPP 25,964 DF 8,655	0.42 0.21	10,905 1,818	.73 .63	7,961 1,145
		10.0	22,958	26,958	LPP 20,218 DF 6,740	0.42 0.21	8,492 1,415	.73 .63	6,199 892
Gravelly	U.S. Forest Service Private Land	2.5	5,882	7,094	LPP 5,320 DF 1,774	0.42 0.21	2,234 373	.73 .63	1,631 235
		0.5	1,176	1,418	LPP 1,063 DF 355	0.42 0.21	446 75	.73 .63	326 47
Pioneers	U.S. Forest Service Private Land	8.2	19,294	23,269	LPP 17,452 DF 5,817	0.42 0.21	7,330 1,222	.73 .63	5,351 770
		0.5	1,176	1,418	LPP 1,063 DF 355	0.42 0.21	446 75	.73 .63	326 47
	TOTAL	34.9	80,940	97,614	97,614		35,874		25,676

ageaverhead National Forest proposed ten year timber sale plan. Gallatin National Forest announced timber sale timber sale program to F.Y. 1988. Personal conversation with industry representatives in the region.

^bConversion: 4.25 BF Scribner Dec. C. per cubic foot (1,000 MBM/4.25 BF = 235.29 x 10 = 2353 cunits.)

^cConversion: 1.206 oven dry tons per cunit. (2,353 cunits x 1.206 = 2838 oven dry tons).

^dConversion: LPP 75 percent, DF 25 percent.

^eKeegan, Charles E. III, The Cost and Availability of Forest Residue in the Northern Rocky Mountains, University of Montana, September 1981. Table 1, page 6.

^fKeegan, Charles E. III, The Cost and Availability of Forest Residue in the Northern Rocky Mountains, University of Montana, September 1981, Table 4, page 14.

VOLUME OF MILL RESIDUE DEVELOPED ANNUALLY
(OVEN DRY TONS)

Plant and Location	Approximate ^a Annual Production Lumber Tally MBM	(.47) Chips ^b BDU/BDTC	(.25) Sawdust ^b BDU/BDTC	(.22) Planer ^b Shavings BDU/BDTC	(0.26) Bark ^b BDU/BDTC	Remarks
Castle Mt. White Sulphur Springs	24,000	11,280/9,400	6,000/5,000	5,280/4,400	624/520	Wood fired boiler system in use.
Brand S Livingston	43,000	20,320/16,842	10,750/8,958	9,460/7,883	1,118/932	Lumber air dried.
Plum Creek Belgrade	30,000	14,100/11,750	7,500/6,250	6,600/5,500	780/650	Wood fired boiler system in use.
Stoltz Lumber Co. Dillon	28,000	13,160/10,967	7,000/5,833	6,160/5,133	728/607	Bark sold locally.
Louisiana Pacific Deer Lodge	42,000	19,740/16,450	10,500/3,750	9,240/7,700	1,092/910	Wood fired boiler system in use.
SUB-TOTAL	167,000	65,409 ODT	34,791 ODT	30,616 ODT	3,619 ODT	TOTAL 134,435 ODT

^aDirectory of Forest Products Industry published production figures.

^bRegional Sawmill Residue Factors published by the Bureau of Business and Economic Research, University of Montana.

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primarily reflects varying transportation costs and does not take into account the upward pressure on residue prices that would occur with the entry of another substantial purchaser into the market for wood residues. Tables III and IV summarize the source and costs inherent in these price estimates. Table V summarizes wood fuel source, type, and cost believed appropriate for the Ennis project.

3. Constraints to Fuel Availability

A number of constraints will reduce the amount of fuel realistically available to the project to less than 25% of the amount physically available. Competing land uses, particularly the pressure to reduce harvest levels on National Forest lands to improve wildlife habitat is one constraint. Steep terrain in much of the region would require more expensive cable skidding and greater road costs, thus reducing the volume of harvested timber and in turn the available residue from the forest. Additionally, forest residue as a fuel source has not been given a very high priority by the Forest Service and until it is, it will be difficult to make fuel harvesting a part of the day-to-day timber sale program. Finally, competing markets, particularly for mill residue in the pulp and paper industries and for local cogeneration projects will significantly reduce the fuel available to the project from mill sources.

TABLE III

COST OF FOREST RESIDUE DELIVERED TO ENNIS
(Dollar per Oven Dry Ton)

IN THE TRUCK LOG FORM

Source	Falling	Skidding	Condensing	Loading	Total
Withycombe	1.67	24.74	-	6.22	32.63
Author (Condensing)	2.20	24.64	5.00	3.52	35.36
(Log)	2.20	24.64	-	7.04	33.88
Timber Thinning					
Project	4.36	5.06	-	-	-
Combes	-	10.00	-	-	-

IN THE TRUCK CHIP FORM

Source	Falling	Skidding	Chipping	Total
Withycombe	1.67	24.74	5.99	32.40
Author	2.20	24.64	6.0	33.04
Timber Thinning				
Project	4.36	5.06	11.58	21.00
Combs	-	10.00	16.00	26.00

HAULING COST MILE PER OVEN DRY TON

Source	Hauling
Withycombe	.112
Author	.074
Combes	.150

TABLE IV

COST OF MILL RESIDUE DELIVERED TO ENNIS
(\$ per Oven Dry Ton)

(1) Source	(2) Haul Distance to Ennis (Miles)	(3) Haul Distance to Missoula (Miles)	(4) Ennis Advantage (Miles/\$00T) Round Trip	(5) Pulp Chips F.O.B. Mill/Ennis	(6) Planner Shavings F.O.B. Mill/Ennis	(7) Sawdust F.O.B. Mill/ Ennis	(8) Bark F.O.B. Mill/Ennis
White Sulphur Springs 2 trips in 12 hrs $\frac{12 \text{ hrs} \times 36.0/\text{hr} = 17.28/\text{ODT}}{25 \text{ ODT}}$ (\$0.93 per running mile)	116	185	+138/\$10.26	24.00/41.28	4.00/21.28	4.00/21.28	6.00/23.28
Livingston 3 trips in 12 hrs $\frac{12 \text{ hrs} \times 36.0/\text{hr} = 11.52/\text{ODT}}{37.5 \text{ ODT}}$ (\$0.90 per running mile)	80	227	+294/\$21.16	22.00/33.52	4.00/15.52	4.00/15.52	6.00/17.52
Belgrade 3 trips in 19 hrs $\frac{10 \text{ hrs} \times 36.0/\text{hr} = 9.60/\text{ODT}}{37.50 \text{ ODT}}$ (\$1.13 per running mile)	53	192	+278/\$25.13	22.00/31.60	4.00/13.60	4.00/13.60	6.00/15.60
Dillon 3 trips in 12 hrs $\frac{12 \text{ hrs} \times 36.0/\text{hr} = 11.52/\text{ODT}}{37.5 \text{ ODT}}$ (\$1.02 per running mile)	70	170	+200/\$16.32	22.00/33.52	4.00/15.52	4.00/15.52	12.00/23.52
Deer Lodge 2 trips in 13 hrs $\frac{13 \text{ hrs} \times 36.0/\text{hr} = 18.72/\text{ODT}}{25 \text{ ODT}}$ (\$0.91 per running mile)	128	79	-98/(\$7.13)	30.00/48.72	4.00/22.72	4.00/22.72	6.00/24.72

TABLE V
MILL AND FOREST RESIDUE VOLUME AND COST
THAT ARE REALISTIC FOR THE ENNIS PROJECT
(Dollar per Oven Dry Ton)

Source and Type	Annual Volume	Cost Range Delivered Ennis	Remarks
Sawdust	12,770	\$13.60 - \$21.28	Assumed that the project purchases 50% of the volume from Livingston, Belgrade, Dillon and White Sulphur Springs.
Shavings	11,458	\$13.60 - \$21.28	
Bark	1,354	\$15.60 - \$23.52	
Forest Residue			Assumed that the project purchases 25% of the volume from the four regions. Hauling cost per oven dry ton from each region were estimated to be: Tobacco Root \$14.51 Madison 13.18 Gravelly 15.75 Pioneers 20.81
Tobacco Root	187	\$47.14 - \$49.87	
Madison	4,049	\$45.81 - \$48.54	
Gravelly	560	\$48.38 - \$51.11	
Pioneers	1,624	\$53.44 - \$56.17	
TOTAL	32,002	\$13.60 - \$56.17	

4. Fuel Collection and Delivery

The most economic method for procuring forest residue is an operation in conjunction with active harvesting operations, either with a local purchaser of National Forest stumpage or through direct purchase of the timber and resale of the merchantable sawlogs.

Because of low fuel volume per acre, limited size of landings and road design, which are dictated by the terrain, in-woods chipping would probably not be feasible. Fuel material would probably have to be delivered to the project site and reduction made there.

All fuel material would be felled prior to skidding. All trees would be left tree length with limbs and tops and skidded in that form. Grapple skidders would skid all the material to the landing, both forest residue and sawlogs. On the landing the trees are limbed and bucked and separated into sawlogs and residue. If residue trees are long enough (40+ feet) they can be delivered to the project site with limbs and tops attached as is being done on the West Coast with loads averaging 25 tons. If the residue material is not suitable for hauling on conventional logging trucks then it must be bundled or baled. Once the material is delivered it can then be processed into chips or stored and processed into fuel as needed.

C. GEOTHERMAL RESOURCE ASSESSMENT

The objective of the geothermal resource assessment task was to formulate a working model of the Ennis geothermal system and to better understand the deeper thermal regime which might supply the temperatures required for a hybrid electric power cycle.

1. Structural Setting

The Ennis geothermal area lies in the Madison Valley, a topographic depression bounded by the Madison Range and by the Tobacco Root and Gravelley Ranges. The Ennis Hot Springs, with the highest surface discharge temperature in Montana (83°C, 181°F), are situated about two miles east of the range front at the southern end of the Tobacco Root Mountains. A general geologic map of the Ennis area is shown in Figure 2.

The north-trending Madison fault along the west side of the Madison range is the most prominent structural feature in the valley and has been associated with considerable historical seismic activity.

The present stress field orientation for the region, consistent with fault plane solutions, should favor the formation of east-west trending normal faults such as the Centennial Fault which bounds the Madison Valley on the south. There are at least two such areas of normal faulting

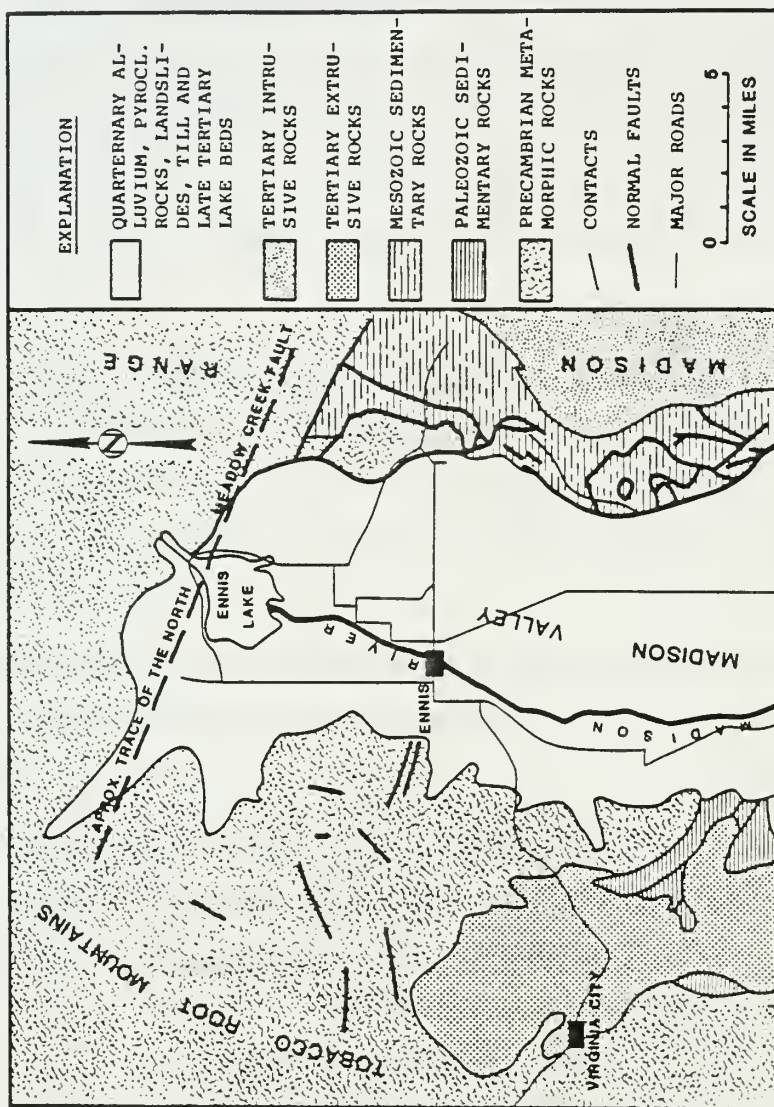


Figure 2: Geologic Map of Ennis Area (modified from Egbert, (1960)

Canyon area south of Ennis and the Meadow Creek fault zone north of Ennis Lake. This latter zone is part of a larger fault system of basement weakness which trends northwest. The faulting along the west side of the valley is less pronounced with shorter, discontinuous segments of smaller displacements. West of Ennis Hot Springs, the Precambrian section has been downdropped in a series of step faults.

2. Geophysical and Temperature Surveys

Regional geophysical studies indicate a basin depth of about 10,900-12,800 meters (6,000 to 7,000 feet) near Ennis with complex faulting along NW and NE to E trends in the Hot Springs area. Generally a resistivity low is centered on the Hot Springs which trends NE while low resistivities also exist to the southeast. At depths of 330-550 meters (180 to 300 feet) this Hot springs low broadens eastward and suggests that either thermal water is rising from depths to the east and moving westward to the springs or rising beneath the springs and flowing eastward in the valley fill. Regretably, recent geophysical work conducted by the Montana Bureau of Mines and Geology and the USGS should have been made available for this study.

Temperature data were obtained from a number of drill holes ranging from 9 to 3 meters (30-1,200 feet) in depth. Some of the gradient profiles show a temperature reversal that may be

indicative of lateral recharge of the main production zone in the well from a connected vertical conduit. This is consistent with a model of thermal fluids rising along steep intravalley faults and moving out and mixing into near surface alluvial aquifers or along the alluvial/bedrock contact. The high thermal gradients in several wells were used to estimate a circulation depth of about 2 km (1.2 miles) which is roughly the base of the valley fill section east of Ennis.

The distribution of heat flow (and isotherms) is greatly affected by the juxtaposition of lithologies of different thermal conductivity. Heat tends to be dissipated in the high conductivity basement rocks at the basin boundary, but tends to accumulate beneath the thick insulating layer of the valley fill section. Figure 3 shows a schematic temperature distribution for the Madison Valley - Ennis system that is important in selecting drilling targets.

3. Conceptual System Model

Generally geothermal systems require tectonic activity to maintain the fracture permeability which promotes deep hydrothermal convection, and this activity is clearly present in the Madison Valley. The flow paths created by faulting allow surface recharged waters to circulate to depths of 2-3 km (1.2 to 1.8 miles) near the base of the valley fill section in the deepest part of the basin east of Ennis. The

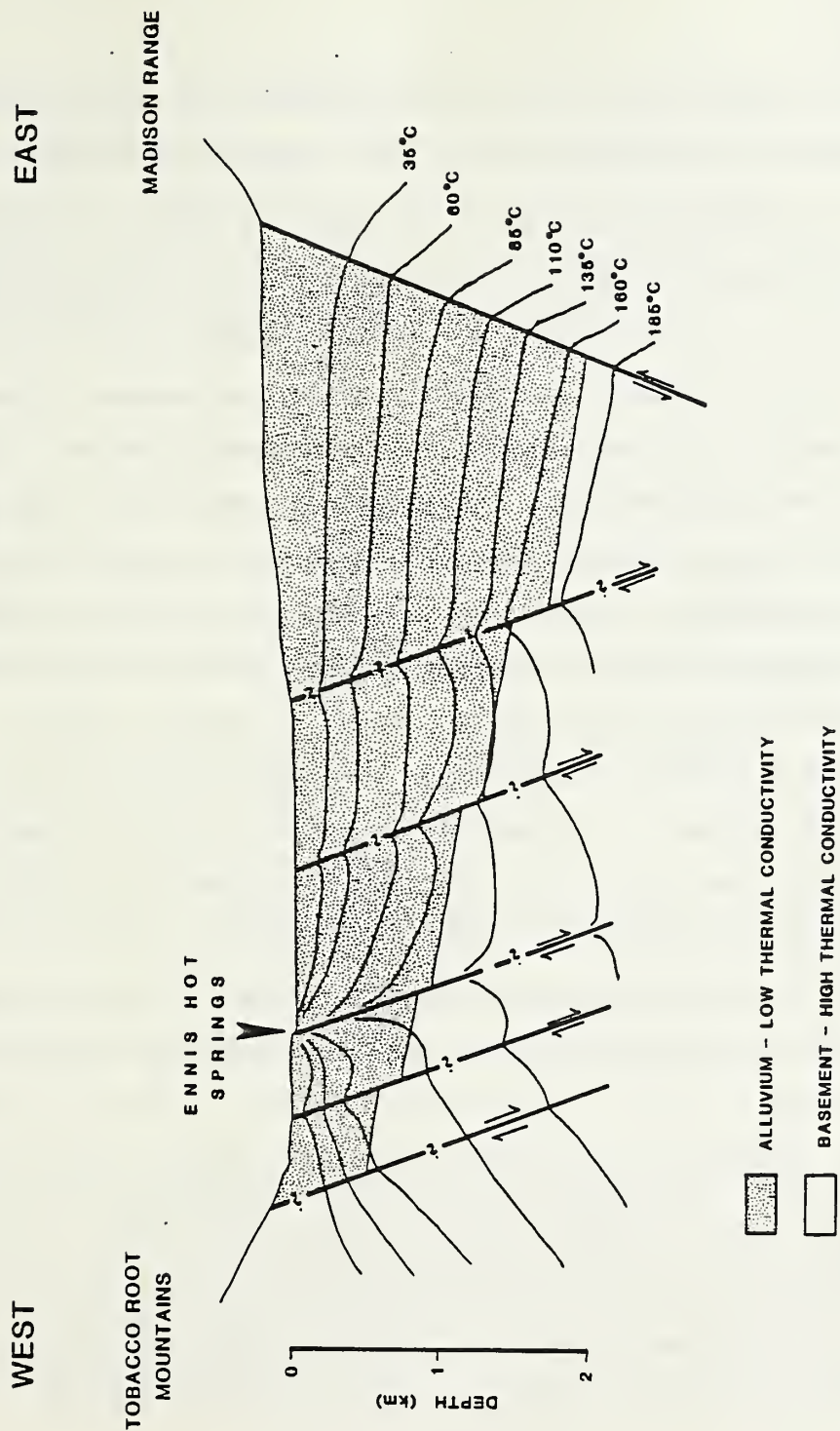


Figure 3: Schematic Subsurface Temperature Distribution in Ennis Area

heat source for the system is probably the above average heat flow of the region as opposed to a magmatic source.

The deep geothermal system at Ennis is probably recharged by precipitation from the adjacent ranges. Although little direct evidence exists to enable determination of the source of recharge it is undoubtedly meteoric. Stable isotope data (Leonard and Wood, 1980) from Ennis Hot Spring are incomplete; however, comparisons of oxygen data from the geothermal waters with data from meteoric waters drawn from regional maps seem to indicate that virtually no isotopic shift has occurred at depth. More complete isotope data should be collected to estimate the recharge area(s). The active hydrologic system in the Madison Valley is an important element of the geothermal model. Strong hydrostatic heads resulting from percolation of runoff at high elevation causes deep water penetration to depths of high temperature. The heated water is then driven up along bounding faults by both the hydrostatic head and the density differential due to heating.

The flow path within the geothermal system is important for the siting of deep drilling targets. The depth of circulation, along with the proposed heat flow and structural models (asymmetric graben), suggest fluids circulating downward along the range front faults close to the base of the

Tertiary section and rising along intravalley faults to discharge north of Ennis. The clay-rich, low-permeability valley fill (including lacustrine beds of the Renova Formation) serves to confine the high temperature fluids within the fractured crystalline basement.

The main production zone tapped by three deep hot wells around the Hot Springs has been in fractured Precambrian gneiss. Flow and pump testing of the wells indicate that they are connected and that rapid communication exists between the wells. Interpreting the well test performed by different organizations in 1982 and 1983 the results suggest:

- a. Transmissivity values of 4000-5000 ft.³/day/ft.
- b. Storativity of approximately 10^{-4}
- c. Rapid response to pumping
- d. No boundary effects were noted during the 24 hour tests.

Sustainable long-term withdrawal rates for wells near Ennis will be limited by the least transmissive section of the flow system with which the well communicates. In the case of the MacMillan well, the log does not show the intersection of any faults. Future drilling which might intersect one of the main conduits of the upflow from depth could provide somewhat more productive wells. Based on the limited testing to date, a minimum production of about 400 gallons per minute (gpm) of

194°F water could be sustained, although the long-term effects on the spring and other wells can not be determined at this time.

4. Exploration Goals and Recommendations

The purpose of this task has been to assess the potential for producing adequate (rate and temperature) geothermal fluid for use in a hybrid power plant. The geothermometry, as well as the measured 209°F temperature in Mac-1 strongly indicate that minimum project temperatures of 220°F (and probably higher) are obtainable at reasonable drilling depths (2000-3000 ft.). The ability of the system to sustain yields on the order of 1000-2000 gpm without excessive pumping lifts can not be determined at present. Future drilling should be targeted on the main (and presumably most permeable) structures in and around the Hot Springs. Drill holes should aim at penetrating these upflow zones deeper in the section for higher temperatures, which will probably necessitate stepping to the east or northeast. Prior to siting an exploratory well some additional consideration of the structure east of the Springs might be warranted. The release of seismic and gravity data by the Montana Bureau of Mines and Geology (MBMG) may be sufficient; alternatively a more in-depth look at the data of Rassmussen and Fields (1983) than has been presented in the literature might constrain the depths of

intravalley faults well enough for confident siting. The pending USGS report on the area should also help delineate some of the faults.

After reviewing the above data, a 2000-3000 ft. thermal gradient or slim hole would allow a testing of the structural and heat flow models at limited risk.

D. CONCEPTUAL ENGINEERING

The task of the engineering analysis was to examine a number of conceptual engineering designs for a modular-sized (15 MW design output) using wood residues as the primary fuel. This design output appears to be an optimum sized plant for most sites, both economically and from the standpoint of wood fuel supply logistics and competing uses for wood residues.

1. Cycle Selection and Description

Three power cycles were examined, two of which incorporate two different geothermal resource temperatures.

The base cycle (Cycle I) is a wood-fired conventional steam turbine configuration with no geothermal contribution. System features include an induced-draft cooling tower, water circulation system, feed water pumps and heaters in a five stage configuration. The wood fuel system consists of a chipper, stacker, metal separator, conveyors, screen, day storage bin, and fuel conveyor to the boiler. The operating parameters at each storage in the cycle can be identified in the table accompanying the power cycle schematic in Figure 4.

Utilizing geothermal heat to dry the wood fuel was considered and rejected because of the additional equipment needed such as a hammermill, additional chip screens, dryers with air pollution controls, and material handling sub-systems for

recycling the fuel. In addition extra operating staff and maintenance expense would be required for fuel drying which is too costly and involved for this installation.

Pollution Control. Flue gas leaving the boiler will pass first through a multi-cyclone particulate separator (recycling solids to the boiler) and second through a 2-stage wet gas scrubber unit for aid in pollution control. An induced draft 120 hp fan exhausts flue gas to the 60 foot stack. The wet gas scrubber is preferred over the electro-static precipitator as a simpler more positive system to capture wood particulates even though the scrubber requires added fan power. Electro-static precipitator performance on wood particles is not a long proven art and the "rapping" practice to clean the unit may cause breakage.

Based on information supplied from equipment vendors, particulate air emissions from the base case wood only plant are estimated to be 24 lbs. per hour.

Emissions from hog fuel boilers are predominately particulates. Wood fuel contains little or no sulfur, and other gaseous emissions including NO_x would be within EPA and MDHES guidelines.

Bottom ash from the boiler grate and fly ash from the flue gas scrubber are collected and conveyed to a hopper for

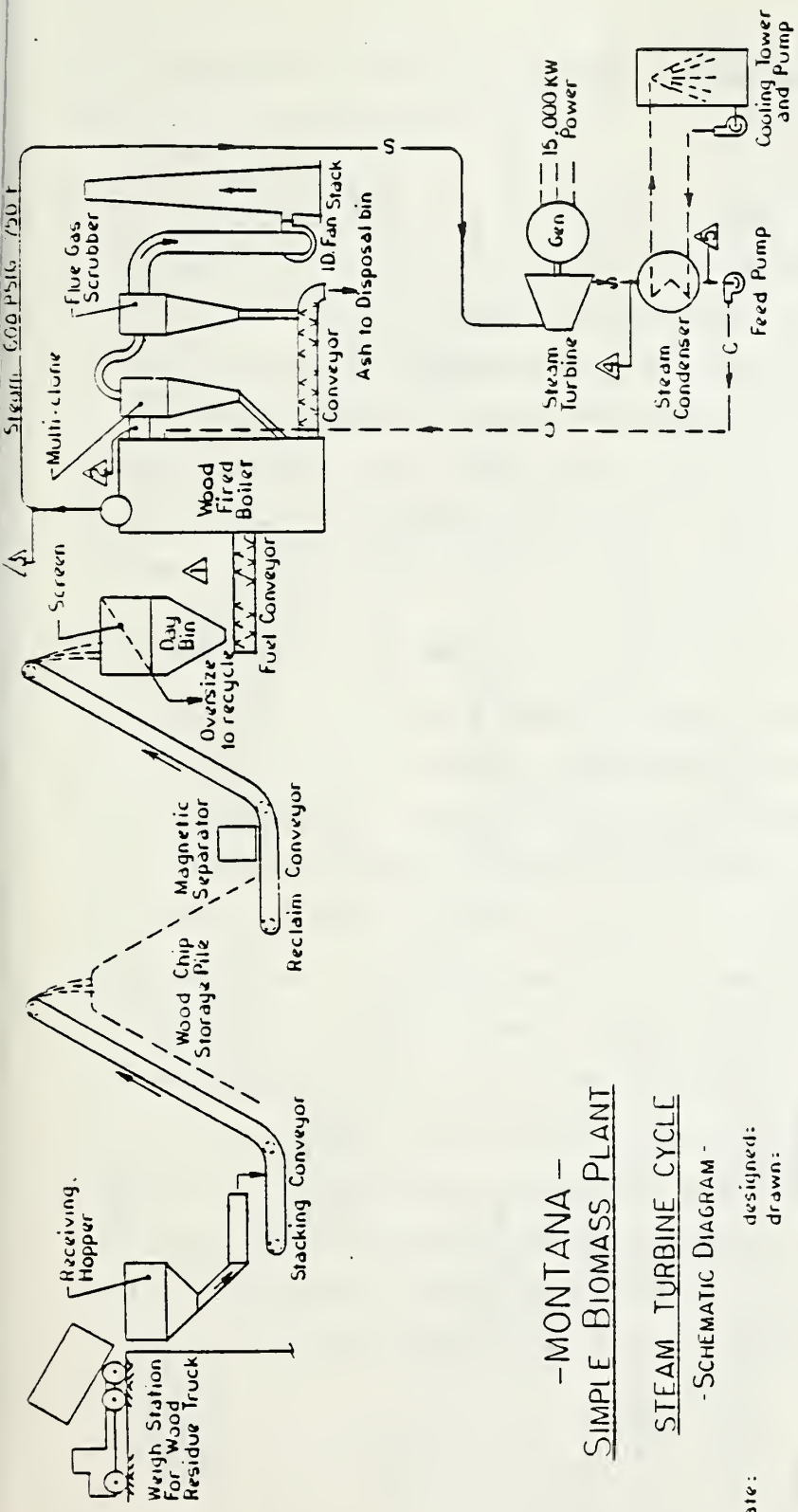
collection and periodic dumping of the ash into a truck container. The system will provide for off-site disposal of the ash, either as a commercial fertilizer or, if not useable, as solid waste.

Powerplant Auxiliaries. Make-up water at about 220 gpm capacity for the plant cooling tower and boiler feedwater will be supplied from fresh water wells. A water treatment system will include chemical feeders and filtration tanks with back wash capability.

A sewage treatment system will be installed to serve the office building.

Residual chemicals in the blow-down streams from the boiler and from the cooling tower will be piped for gravity drainage to an evaporation pond. A diked earthen pond with an impervious liner will concentrate the chemical solids in the bottom of the pond. Excess water will be evaporated off while chemicals will be accumulated in the pond for the life of the project.

Six-inch water mains will be buried below the frost line around the plant perimeter and wood chip pile with 4 fire hydrants connected and guarded. The parking lot, access road and chip van trucks turn around will be paved.



-MONTANA - SIMPLE BIOMASS PLANT

STEAM TURBINE CYCLE -SCHEMATIC DIAGRAM -

date: _____ designed: _____
drawn: _____

STREAM NO.	1	2	3	4	5
DESCRIPTION	Plant Fuel Supply	Flue Gas	Steam Supply to Turbine	Steam Turbine Exhaust	Boiler Feed Water
Flow lbs/hr	21661	138000	98550	98550	98500
Pressure Psig	-	-	600	1.5 HgA	
Temp °F	70°	400°	825°		70°
Enthalpy BTU/lb	8860		1421.4		319.5
BTU/hr output	1.91x10 ⁶				
BTU/hr input					

Figure 4

The site will include a 6 foot high cyclone fence around the plant perimeter.

The second power cycle (Cycle IIA, IIB) incorporates geothermal energy at 275°F and 250°F, respectively, into the wood fuel steam boiler configuration described above. The cycle employs two additional heat exchangers to preheat the combustion air and boiler feedwater for the wood-fired steam cycle. Figure 5 portrays this cycle (with 275°F geothermal entering temperature) with accompanying mass flow and energy data.

The addition of a geothermal heater for the boiler feedwater improves cycle performance because steam that is normally required to heat the condensate remains in the turbine to release its energy for power generation. This effect is reflected in a reduction in wood fuel requirements for a constant electrical generation. Table 6 summarizes the theoretical performance gains attributable to using geothermal fluids (at three different source temperatures) for boiler feedwater heating. For a plant with a nominal yearly wood fuel requirement of 365,000 OD tons, fuel savings could be as high as 7.3% and the thermal contribution of geothermal energy to power production could range as high as 11.8%. Figure 6 depicts the behavior of several variables as a function of geothermal feedwater heating temperature.

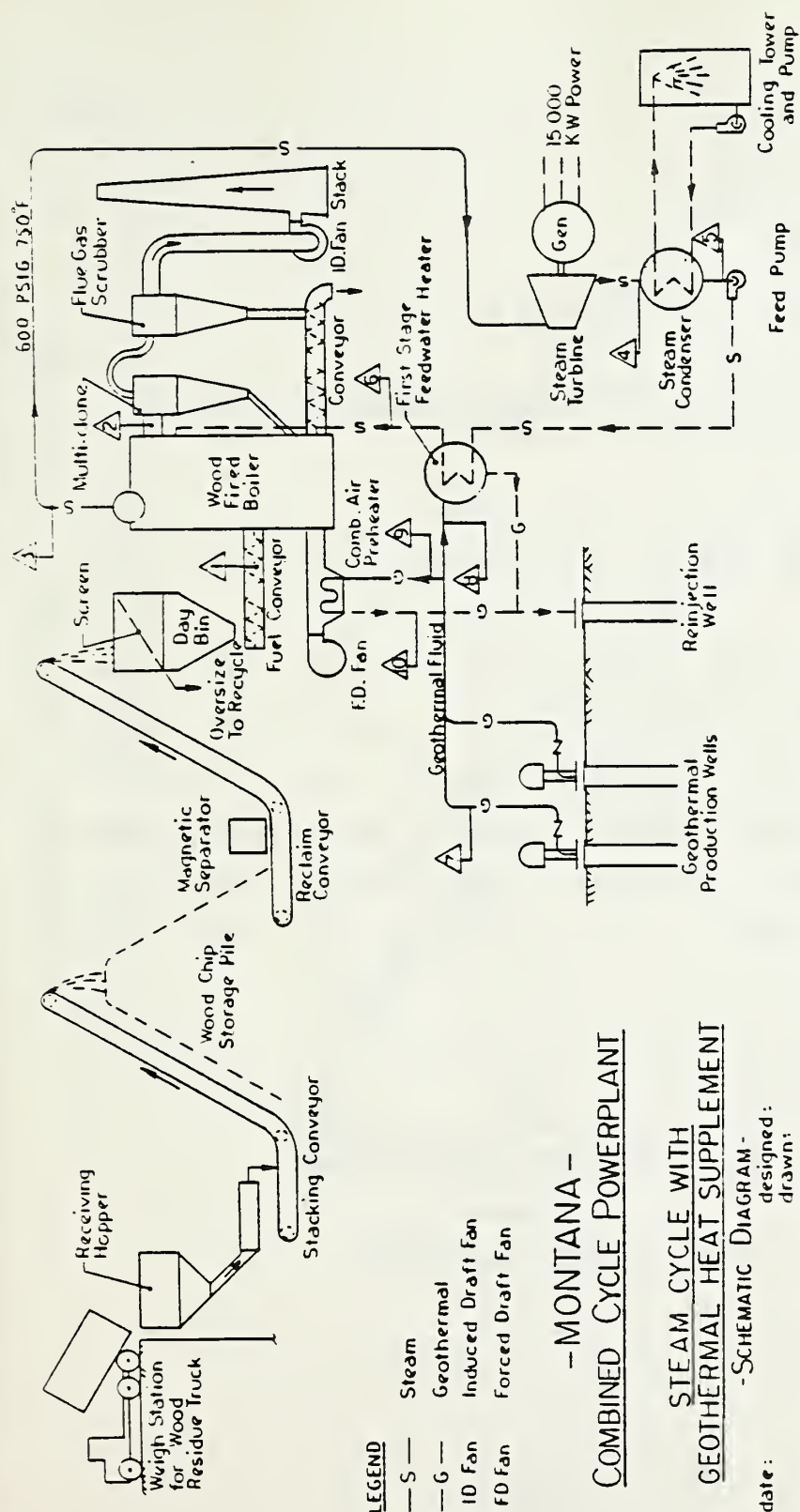


Figure 5

—MONTANA— COMBINED CYCLE POWERPLANT

STEAM CYCLE WITH GEOTHERMAL HEAT SUPPLEMENT

date:
designed:
drawn:

LEGEND

- S — Steam
- G — Geothermal
- ID Fan Induced Draft Fan
- FD Fan Forced Draft Fan

STREAM NO.	1	2	3	4	5	6	7	8	9	10
DESCRIPTION	Plant Fuel Supply	Flue Gas	Steam Supply to turbine	Steam Turbine Exhaust	Feed Water	Feed Water out of 1st Stage	Geothermal Fluid Supply	Geoth. to Feedwater Heater	Geothermal to air Preheater	Geothermal Fluid Supply
Flow, lbs/hr	18071	116000	98550	98500	98500	98500	225800	164000	56800	225800
Press., PSIG	0	0	600	1.5" Hg	—	725	43	43	43	20
Temp., °F	70°	400°	825°	70°	70°	255°	275°	275°	275°	165°
Enthalpy, BTU/lb	8860	—	1421.4	—	319.5	504.5	524	524	524	414
BTU/hr. output	—	—	136x10 ⁶	—	—	—	24.3 x 10 ⁶	18.2 x 10 ⁶	6.1 x 10 ⁶	—
BTU/hr. input	100 x 10 ⁶	—	—	—	—	—	106 net	106 net	105 net	—

Table 6

PERFORMANCE GAINS FROM GEOTHERMAL COMBUSTION AIR HEATING

Geothermal Temp., F	No Geo.			
	Heating	225	275	340
Geo. Flow, gpm	0	333	313	298
Geo. Heat, MM Btu/Hr	0	20.860	27.482	35.886
% Geo. Heat	0	3.2	4.2	5.5
Fuel Saved, Wet Tons/Yr	0	24,695	32,728	42,705
Fuel Saved, O.D. Tons/Yr	0	12,150	16,102	21,011
% Fuel Saved	0	4.6	6.1	7.9

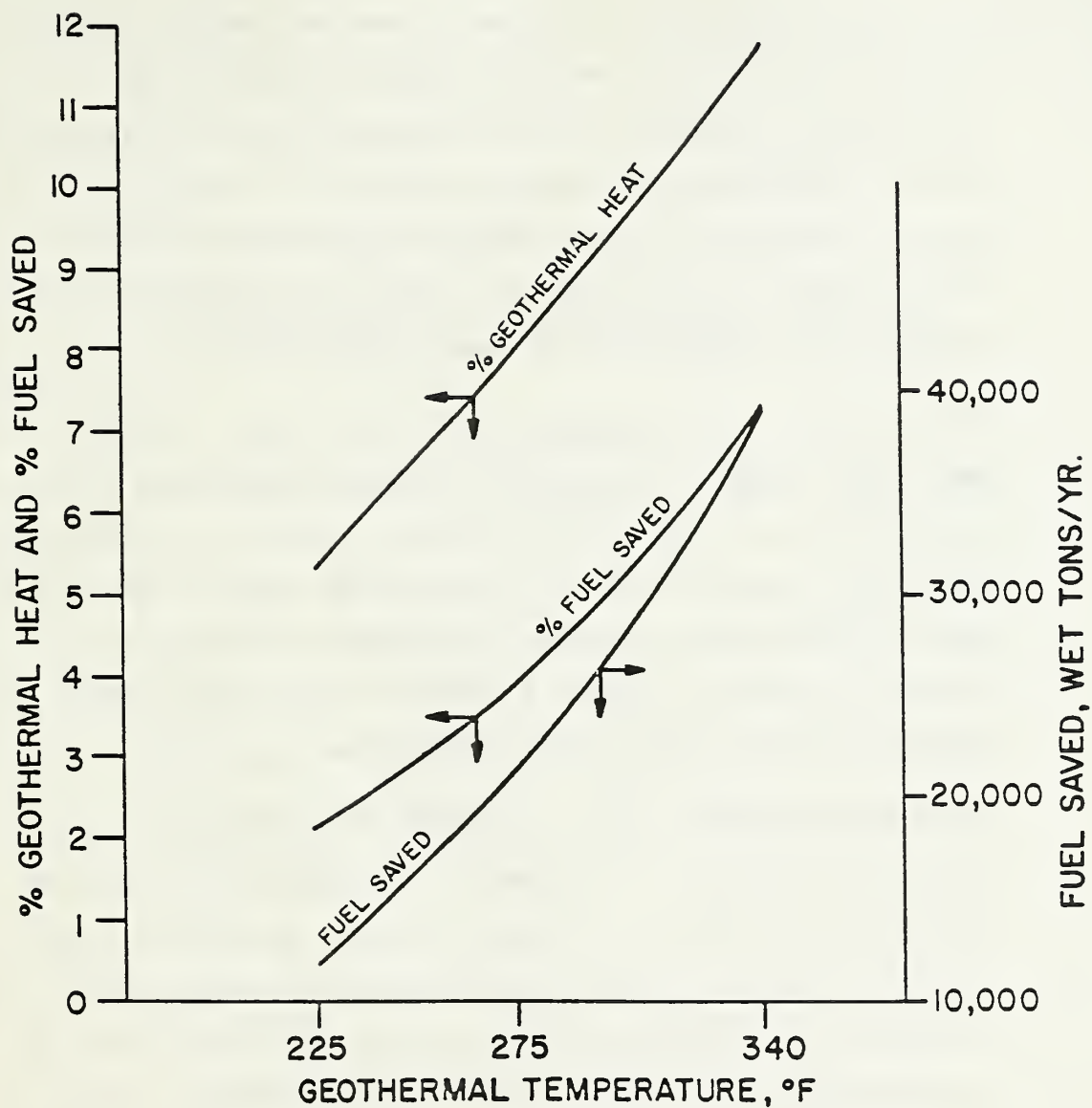


FIGURE 6
GEOTHERMAL FEEDWATER HEATING

Similarly, geothermal energy can be used to preheat the combustion air in the conventional wood-steam cycle, thus improving cycle performance and decreasing wood fuel requirements. The addition is shown as Stream 9 in Figure 5. Table 7 and Figure 7 depict the cycle performance gains attributable to using geothermal fluids for combustion air heating over a wide range of source temperatures.

The last power cycle studied (Cycle IIIA, IIIB) also uses geothermal energy to heat combustion air for the wood-fired steam boiler (but not boiler feedwater), but more importantly the fluids are also used in a binary power cycle to contribute 11 MW of the 15 MW (with 275°F source temperature) developed at the plant. Figure 8 shows the power cycle schematic and accompanying energy and mass flow data.

This low temperature power generation loop will use a binary working fluid (such as isobutane or isopentane) in a Rankine cycle which includes two stages of binary vaporizers, a gas expansion turbine, a water cooled binary condenser, and a condensate feed pump for pressurizing and returning fluid to the two vaporizers. A heat recovery heat exchanger within the binary loop may be added (not shown), depending upon the superheat in the binary exhaust.

The first stage binary vaporizer is heated by entering low temperature geothermal fluids (250 - 275°F). The second

Table 7

PERFORMANCE GAINS FROM GEOTHERMAL COMBUSTION AIR HEATING

Geothermal Temp., F	No Geo.			
	Heating	225	275	340
Geo. Flow, gpm	0	333	313	298
Geo. Heat, MM Btu/Hr	0	20.860	27.482	35.886
% Geo. Heat	0	3.2	4.2	5.5
Fuel Saved, Wet Tons/Yr	0	24,695	32,728	42,705
Fuel Saved, O.D. Tons/Yr	0	12,150	16,102	21,011
% Fuel Saved	0	4.6	6.1	7.9

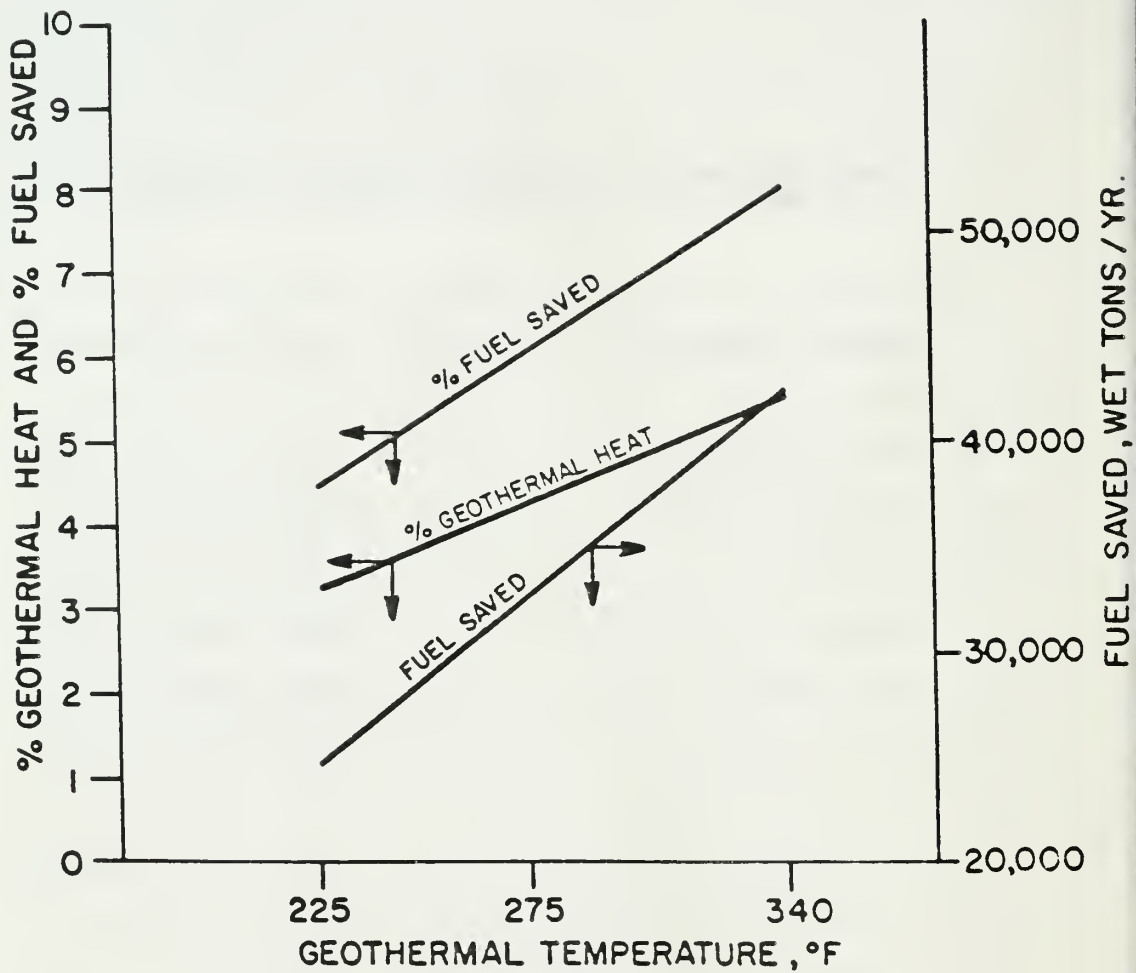


FIGURE 7
GEOTHERMAL AIR HEATING

stage binary vaporizer is heated by entering superheated exhaust steam (about 335°F) which is condensed at a saturated condition of 57.5 psia and 290°F. The binary condenser is cooled by water circulated from a cooling tower. The binary cycle net efficiency is estimated to be about 15%.

2. Wood Fuel Requirements Summary

To note the effect on wood fuel consumption of incorporating geothermal energy into the basic wood-fired steam cycle, the following wood fuel requirements summary is provided (units are in oven dry tons):

	<u>lb/Hr</u>	<u>Tons/Hr</u>	<u>Tons/Yr</u> <u>(85% CF)</u>	<u>Savings</u>
Cycle I	21,661	10.8	80,417	-
Heating Cycle II-A (275°F)	18,071	9.0	67,014	17%
Heating Cycle II-B (250°F)	18,459	9.2	68,503	15%
Binary Cycle III-A (275°F)	15,281	7.6	56,590	30%
Binary Cycle III-B (250°F)	15,754	7.9	58,823	27%

3. Capital Costs

Preliminary plant capital costs are summarized in Table 8. Unit prices are based on vendor quotations, from R.S. Means and Company estimating manual and previous work conducted on similar facilities by International Engineering Company and GeoProducts Corporation. Details of the capital cost estimate are contained in Milestone Report #4 which is attached as an appendix.

Table 8

CAPITAL COST SUMMARY

(\$000's 1984)

	Cycle I	Cycle II-A	Cycle II-B	Cycle III-A	Cycle III-B
Direct Investment					
Wood System	9554.00	9047.76	9071.74	6132.41	6131.41
Binary System	-	-	-	11770.00	11770.00
Geothermal System	-	1362.20	1362.20	1362.20	1362.20
Total Direct	9554.00	10409.96	10433.94	19264.61	19264.61
Indirect Investment					
Performance Bond (1.2%)	114.65	124.92	125.21	235.50	235.50
Construction Permit (2.0%)	191.00	208.20	208.68	392.49	392.49
Construction Income (.7%)	66.88	72.87	73.04	137.37	137.37
Contractor's Mobilization (12%)	1146.48	1249.20	1252.07	2354.95	2354.95
Engineering Fee (8%)	764.32	832.80	834.72	1569.97	1569.97
Construction Management Fee (3%)	286.62	312.30	313.02	588.74	588.74
Total Indirects	3143.19	3424.89	3432.78	6456.50	6456.50
Total Plant & Equipment	12697.19	13834.85	13866.72	25721.11	25721.11
Land (40 Acres @ \$1000/Ac.)	40.00	40.00	40.00	40.00	40.00
Total Engineering Cost*	12163.95	13250.25	13280.68	24583.63	24583.63

* These costs do not include items necessary for project operation, such as Working Capital, Development Costs, and 60 Kv Service, which are used as the basis for the project economic analysis.

E. MARKETING AND SALES

At this time this project investigation commenced (in late 1983), it appeared that the uncertainty that characterized the market for QF-produced power in Montana would be resolved, and that sufficiently attractive market incentives (primarily in power purchase rates) would shortly be in place to warrant the commitment of private capital for small power projects. The Montana Power Company (MPC) was thought to be the most likely power purchaser, although power sales could possibly be made with Pacific Power and Light, Bonneville Power Administration, Idaho Power and Light as well as with electric power cooperatives. The first year power purchase rate then being offered by MPC (6.3¢/kwh) seemed attractive enough that the project seemed worth pursuing, even though the purchase escalation rate was not fixed (and in fact could decline) and was determined annually.

Throughout late 1983 and 1984 the Public Service Commission (PSC) held rate hearings involving all utility companies with marketing areas in the state. It was widely anticipated that avoided cost determination and rate structures ordered by the PSC as a result of those hearings would strongly encourage the development of smaller, decentralized power stations based on the wealth and diversity of Montana's renewable resources.

The hearings did not produce the results which potential small power producers had hoped for, and in fact they had a further depressing effect on the already ambiguous buy-back rate struc-

ture. The PSC had been convinced by the utility companies that their "avoided costs", which serve as the basis for fixing power purchase rates were actually lower than the 6.3¢ per kilowatt hour (/kwh) then being offered, and the new first year contract rate was fixed at about 5¢/kwh, with relatively unattractive escalation schedules.

Although the whole question of avoided costs and new power development strategies (centralized against renewable resource-based decentralized stations) is far from resolved in Montana, it has become clear that for the near term at least, and contrary to the expectations held by most in 1983, that MPC cannot be considered the most likely purchaser of power from a fuel-based small power project. Recent contract experience with PPL similarly indicates that purchase rates are not attractive enough for most small power projects. Regulatory and legal pressures are also currently being exerted on initially favorable rates offered small power producers by Idaho Power Company which, together with wheeling costs, make sales to that utility also problematic. Rural co-ops and BPA do not offer sufficiently high power sales rates to economically justify most small power projects.

Except for certain cogeneration and hydroelectric projects it is difficult to see how power from any QF can be economically marketed in Montana at the present time. The picture may change several years in the future as the current power surplus in the northwest disappears and utility companies develop more geographically diverse marketing strategies.

F. ECONOMIC ANALYSIS

Other than a description of the methodology used in the assessment of the economics of the proposed project, which are standard in the financial community, little of substance can be said regarding the results of the analysis, other than the observation that given the capital, revenue and operating cost relationships, none of the cycles studied can be considered economically attractive.

As the economic analysis summaries shown in Tables 9, 10 and 11 indicate, the rate of return on each of the cycles is substantially below the minimums associated with a sound business investment. In today's financial community investments that yield a 15% return after tax are considered marginal.

In order to make the contemplated project feasible power sales revenues would have to increase over 200% or the combined capacity and energy component would have to be between \$.075 to \$.085 per kilowatt hour.

In the recent past several financing alternatives have been available to developers and owners of energy facilities. The more attractive alternatives (lower effective interest rates) have centered around methods that transfer the favorable depreciation and tax credit treatment to qualified project participants. These methods were outlined but not explored in light of the negative project economics.

TABLE 9

MADISON COUNTY HYBRID POWER PLANT SUMMARY CYCLE 1 (\$000)

PERIOD YEAR	1 1985	2 1986	3 1987	4 1988	5 1989	6 1990	7 1991	8 1992	9 1993	10 1994	11 1995	12 1996	13 1997	14 1998	15 1999
INVESTMENT IN PLANT AND EQUIPMENT															
CUMULATIVE INVESTMENT	\$73 7,663	6,847	254	0	0	0	0	0	0	0	0	0	0	0	0
	73 7,736	14,583	14,837	14,837	14,837	14,837	14,837	14,837	14,837	14,837	14,837	14,837	14,837	14,837	14,837
CONSTRUCTION LOAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LONG TERM FINANCING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EQUITY	73 7,663	6,847	254	0	0	0	0	0	0	0	0	0	0	0	0
GROSS REVENUE	0	0	0	3,838	4,022	4,219	4,430	4,656	4,897	5,156	5,432	5,728	6,045	6,384	6,747
WHEELING CHARGES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ADJUSTED GROSS REVENUE	0	0	0	3,838	4,022	4,219	4,430	4,656	4,897	5,156	5,432	5,728	6,045	6,384	6,747
COST OF REVENUE	0	0	0	(4,192)	(4,390)	(4,599)	(4,819)	(5,049)	(5,291)	(5,546)	(5,813)	(6,094)	(6,390)	(6,700)	(7,026)
OTHER EXPENSES	0	0	0	(2,153)	(3,142)	(3,000)	(3,000)	(3,000)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
TAXABLE INCOME	0	0	0	(2,507)	(3,510)	(3,381)	(3,389)	(3,394)	(427)	(423)	(414)	(399)	(378)	(349)	(313)
TAXES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AFTER TAX CASH FLOW	(\$73) (7,663)	(6,847)	(609)	(369)	(380)	(389)	(389)	(393)	(394)	(390)	(381)	(366)	(345)	(316)	(280)
CUMULATIVE AFTER TAX CASH FLOW	(\$73) (7,736)	(14,583)	(15,191)	(15,560)	(15,940)	(16,329)	(16,722)	(17,116)	(17,506)	(17,897)	(18,288)	(18,679)	(19,070)	(19,461)	(19,851)

Capacity Factor 87%

Annual million Kwhr Sold 101.33

Wood Fuel (00T/hr)

Geothermal Fluid (gpm) 0

Internal Rate of Return -0.42%

TABLE 10

MADISON COUNTY HYBRID POWER PLANT SUMMARY CYCLE 11-A (1980)

PERIOD YEAR	1 1985	2 1986	3 1987	4 1988	5 1989	6 1990	7 1991	8 1992	9 1993	10 1994	11 1995	12 1996	13 1997	14 1998	15 1999
INVESTMENT IN PLANT AND EQUIPMENT CUMULATIVE INVESTMENT	\$79 8,382	7,419 15,801	223 16,024	0 16,024	0 16,024	0 16,024	0 16,024	0 16,024	0 16,024	0 16,024	0 16,024	0 16,024	0 16,024	0 16,024	0 16,024
CONSTRUCTION LOAN LONG TERM FINANCING EQUITY	0 0 79	0 0 8,303	0 0 7,419	0 0 223	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0
GROSS REVENUE WHEELING CHARGES	0 0	0 0	0 0	3,740 0	3,919 0	4,111 0	4,317 0	4,537 0	4,773 0	5,024 0	5,294 0	5,582 0	5,891 0	6,221 0	6,574 0
ADJUSTED GROSS REVENUE	0	0	0	3,740	3,919	4,111	4,317	4,537	4,773	5,024	5,294	5,582	5,891	6,221	6,574
COST OF REVENUE OTHER EXPENSES	0 0	0 0	0 0	(3,809) (2,329)	(3,989) (3,400)	(4,179) (3,247)	(4,378) (3,247)	(4,587) (3,247)	(4,807) (36)	(5,039) (36)	(5,282) (36)	(5,538) (36)	(5,808) (36)	(6,091) (36)	(6,388) (36)
TAXABLE INCOME TAXES	0 0	0 0	0 0	(2,399) 0	(3,470) 0	(3,314) 0	(3,307) 0	(3,297) 0	(3,297) 0	(3,297) 0	(3,297) 0	(3,297) 0	(3,297) 0	(3,297) 0	(3,297) 0
AFTER TAX CASH FLOW CUMULATIVE AFTER TAX CASH FLOW	(\$79) (479)	(8,303) (8,382)	(7,419) (15,801)	1293 (16,094)	1701 (16,164)	(671) (16,231)	(611) (16,292)	(501) (16,342)	(351) (16,376)	(141) (16,391)	12 (16,379)	44 (16,335)	83 (16,252)	131 (16,121)	186 (15,935)

Capacity Factor
Annual million Kwhr Sold 87%
98.75

Internal Rate of Return 1.72%

Wood Fuel (MDF/hr) 9.00
Geothermal Fluid (gpm) 451

01/23/85

GEOPRODUCTS CORPORATION OAKLAND, CALIFORNIA

01/23/8

TABLE 11

MADISON COUNTY HYBRID POWER PLANT SUMMARY CYCLE 111-A (\$000)

PERIOD YEAR	1 1985	2 1986	3 1987	4 1988	5 1989	6 1990	7 1991	8 1992	9 1993	10 1994	11 1995	12 1996	13 1997	14 1998	15 1999
INVESTMENT IN PLANT AND EQUIPMENT															
CUMULATIVE INVESTMENT															
	142	14,899	13,312	239	0	0	0	0	0	0	0	0	0	0	0
	142	15,042	28,354	28,593	28,593	28,593	28,593	28,593	28,593	28,593	28,593	28,593	28,593	28,593	28,593
CONSTRUCTION LOAN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LONG TERM FINANCING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EQUITY	142	14,899	13,312	239	0	0	0	0	0	0	0	0	0	0	0
GROSS REVENUE	0	0	0	3,740	3,919	4,111	4,317	4,537	4,773	5,024	5,294	5,582	5,891	6,221	6,574
WHEELING CHARGES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ADJUSTED GROSS REVENUE	0	0	0	3,740	3,919	4,111	4,317	4,537	4,773	5,024	5,294	5,582	5,891	6,221	6,574
COST OF REVENUE	0	0	0	(3,830)	(4,002)	(4,184)	(4,375)	(4,576)	(4,788)	(5,010)	(5,244)	(5,491)	(5,750)	(6,022)	(6,309)
OTHER EXPENSES	0	0	0	(4,152)	(6,060)	(5,787)	(5,787)	(5,787)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
TAXABLE INCOME	0	0	0	(4,242)	(6,143)	(5,860)	(5,845)	(5,826)	(80)	(50)	(15)	28	77	135	202
TAXES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AFTER TAX CASH FLOW	(142)	(14,899)	(13,312)	(329)	(83)	(73)	(58)	(39)	(15)	14	50	92	141	199	266
CUMULATIVE AFTER TAX CASH FLOW	(142)	(15,042)	(28,354)	(28,683)	(28,766)	(28,839)	(28,897)	(28,936)	(28,952)	(28,930)	(28,888)	(28,796)	(28,655)	(28,456)	(28,190)

Capacity Factor 87%
Annual million Kwhr Sold 98.75

Internal Rate of Return 0.67%

Wood Fuel (00T/hr) 7.60
Geothermal Fluid (gpm) 3560

G. ENVIRONMENTAL AND REGULATORY PLANNING

This section summarizes the significant environmental issues related to the proposed project and the permitting sequence applicable to the project. The major environmental issues are air quality maintenance, liquid and solid waste discharges, and certain geotechnical issues.

1. Air Resources

The wood consumption rate of the project would vary from about 160 tons per day (tpd, oven dry basis) to 220 tpd, depending on the final power cycle selected. Although various means exist to control particulate and gaseous emissions and would have to be employed on this or any similar project, Table 12 identifies the unabated emission levels from a 15 MW plant burning about 220 tpd of wood fuel.

Gaseous emissions from hogged fuel are minimal. Sulfur, nitrogen oxides, and carbon monoxide emissions would all be well within EPA and state guidelines and would require no means of control. Particulates entrained in the flue gases are substantial, however, and would require control technology. Particulates include unburned carbon and hydrocarbons, unburned wood particles, and sand or dirt carried into the boiler with the fuel.

TABLE 12

ESTIMATES OF UNABATED ATMOSPHERIC EMISSIONS
FROM A 15 MW WOOD-GEOTHERMAL POWER PLANT

(wood combustion rate estimated at 220 dry tons per day)

	lb/hr	lb/day	Ton/year
Particulates ^a	229	5,496	1,003
Sulfur Oxides ^b	.92	22	4
Carbon Monoxide ^c	92	2,200	400
Hydrocarbons ^d	37	888	162
Nitrogen Oxides ^e	18	432	79

a Based on 25 lb/ton, as the percentage of bark increases, particulates increase.

b Estimated at 0.10 lbs/ton, based on an assumed bark sulfur content of 0.1%, wood-fuel composed of 25% bark, and 10% stoichiometric conversion of sulfur to SO₂.

c Estimated at 10 lb/ton wood.

d Estimated at 4 lb/ton wood.

e Estimated at 2 lb/ton wood.

Three methods of particulate control were evaluated: electrostatic precipitators (ESP), baghouses, and wet scrubbers.

These control methods are generally considered to be capable of controlling particulates to within specified EPA guidelines. With any of these systems a multiple cyclone collector precedes the secondary gas cleanup equipment. An induced draft fan is located immediately following the mechanical collector to provide positive pressure in the final cleaning phase.

Of the three secondary cleanup systems available, a wet gas scrubber is preferred over the ESP as a simpler more positive system to capture wood particulates, even though the scrubber requires added fan power (Figure 9). ESP performance on wood particles is not well established.

Baghouses or fabric filters are rarely used on hogged fuel boiler applications due to the extreme fire hazards present. Additionally, there is potential for moisture condensation in the baghouse because of the high moisture content of fuel burned in wood-fired boilers.

In the overall sense, beneficial effects in air emissions may be argued for plant-controlled burning of wood slash which would normally be burned uncontrolled in the forest causing considerably more emissions. However, forest burning is not

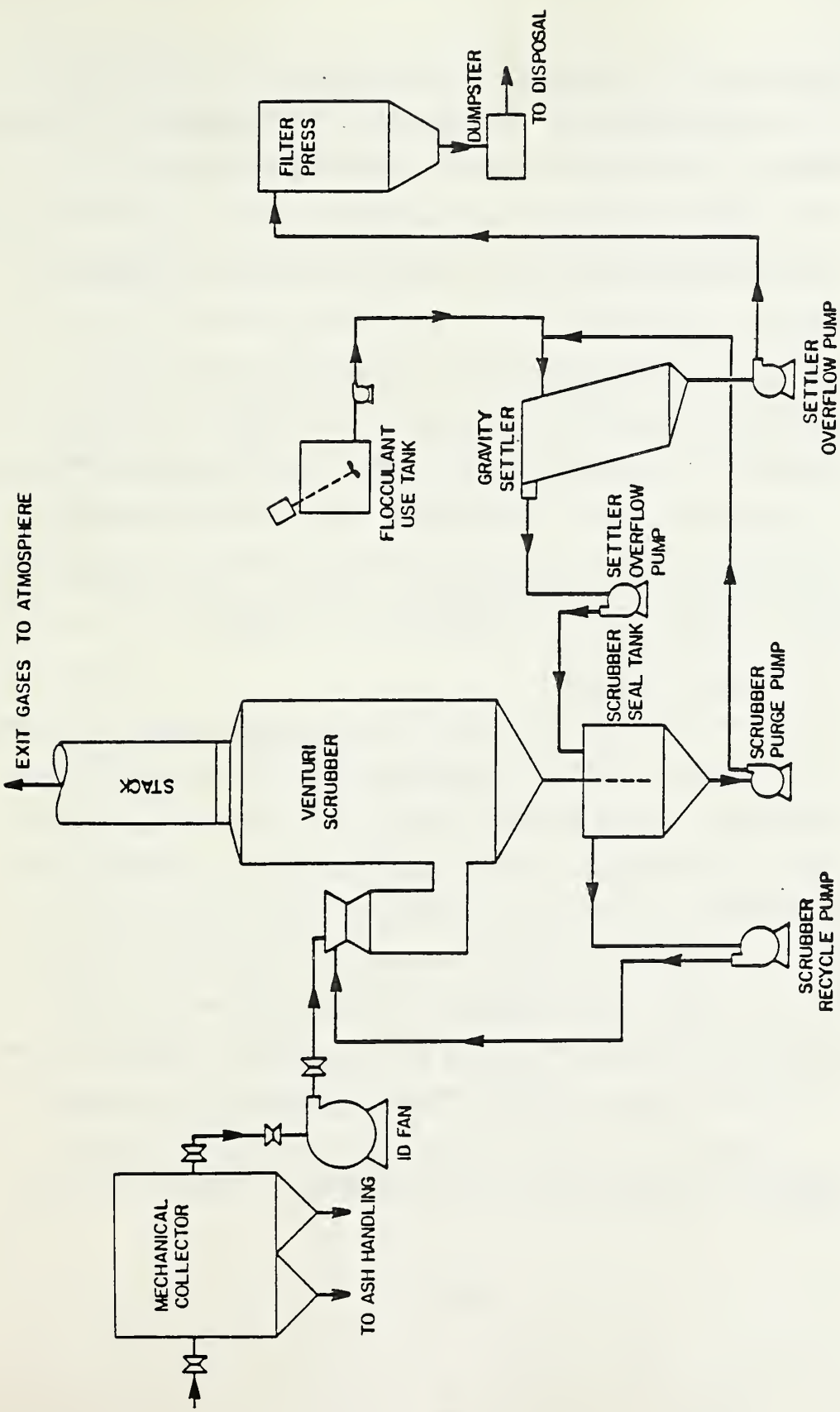


Figure 9

recognized in EPA regulations as a "source", and so the offset would probably not be recognized. Nevertheless, this and similar wood resource based projects which lessen the requirement for uncontrolled burning of slash material in the forests will contribute to overall cleaner air in mountain areas.

The use of geothermal fluids, depending on their nature, could also contribute to air quality concerns. If the fluids are used in the plant cooling system or are discharged to the surface rather than injected back into the ground, emissions of dissolved gases or salts could occur and be noticeable at least in the immediate vicinity of the project.

2. Solid Waste Discharges

The principal source of solid waste from the project would be the combustion residue from burning wood waste, both fly and bottom ash. It is estimated that 2 - 4 tons of ash would be produced daily.* If this ash were buried in a landfill with an in-place density of 100 pounds per cubic foot, a net volume of 10 - 20 acre-feet would be required over a 30 year project life. This disposal method would depend upon the nature of the water table and upon a chemical analysis of the ash, with the major concern being its salt content and the

* Based on a maximum wood fuel consumption of 220 T/d for the wood only plant cycle.

resulting threat of groundwater pollution. If a proper land-fill site should not exist near the project site, one would have to be found elsewhere and the ash trucked to a suitable site.

A possible method for reducing both the environmental and economic problems associated with ash disposal is to develop a market for its use as an agricultural fertilizer, as a source of potassium, or mixed with compost. Fly ash from coal-fired plants has been used in concrete, an application that might apply also for wood ash.

Residual solid wastes from the evaporation pond will also have to be trucked to an approved disposal site for chemical waste.

3. Liquid Waste Discharges

Depending upon its quality, used geothermal fluids may be disposed of by injection or surface means so long as the receiving surface water body is not adversely affected. The fluid chemistry may dictate that the fluids be injected back into the ground. Injection may also be required for reasons other than fluid chemistry; reservoir management and the need for pressure maintenance to prevent subsidence (depending on the depth and geology of the producing formations) may likewise dictate that geothermal fluids be injected.

Injection of waste streams other than the geothermal water runs the risk of degrading the geothermal reservoir or fresh water aquifers. Surface disposal requires concern for degradation of surface waters from harmful amounts of hydrocarbons, solids, metals, and chemicals. Percolation and lined evaporation ponds are both means of disposing of several other liquid waste streams including wastes (runoff) from paved areas, cooling system and boiler blowdown, water treatment system discharges, ash handling discharge, and oily and chemical wastes. The method chosen would be based in part by the depth to fresh water zones in the project area. In areas where near surface fresh aquifers exist, a lined evaporation pond would have to be used for all liquid wastes except for the used geothermal fluid.

Sanitary wastes would be handled by a septic system or, depending on the water table level, a modular aeration-sedimentation system where the liquid effluent is conveyed to the evaporation pond and solids are periodically removed by truck. Handling these liquid waste streams by evaporation would require a 1½ - 2-acre lined pond about 4 feet deep.

4. Permits and Permit Procedures

- a. Major Facility Siting Act. The principal vehicle governing the siting of large projects which convert,

generate, or distribute energy in Montana is the Major Facility Siting Act.*

If a transmission intertie point exists within 10 miles of the plant site, plant cycles I and II would both be exempt from the provisions of the Act, unless the geothermal heating of air and feedwater in cycle II is interpreted by the State to be "geothermally derived" power. Plant cycle III using a two stage binary cycle would fall within the meaning of the Act.

A developer undertaking the future development of a geothermal based facility must file annual long range plans with the Montana Department of Natural Resources and Conservation (DNRC); however, under the Major Facility Siting Act a certificate from DNRC is not required for field exploration.

A formal application for facility development in the post-exploration phase is made jointly to DNRC and the State Department of Health and Environmental Services (DHES). The accompanying filing fee is based on the projected cost of the project. Time limits for processing the application are established in the act as follows:

* 75-20-101, M.C.A.

- a. 90 days to determine if the application is complete and in compliance;
- b. 12 months from date of application acceptance, DHES must determine whether the project complies with air and water quality standards;
- c. 22 months from date of application acceptance, DNRC must have completed its study and environmental impact statement;
- d. 120 days after receipt of DNRC report and recommendations, a public hearing must have been held;
- e. 120 days from date of hearing, the hearing examiner findings must have been submitted and the certificate granted or denied.

If the certificate is issued, and notwithstanding other laws, no other state or local agency may require any permits or other authorizations for construction or operation of the facility, except that state and water quality agencies shall retain authority to enforce compliance with state and federal standards.

- b. Environmental Impact Statements. If the project can be classified as exempt from the provisions of the Major Facility Siting Act, a shorter, though less coordinated environmental certification process must be pursued.

In a preliminary environmental review, the state agency having primary permit jurisdiction over the project will determine the significance of potential environmental effects of the proposed project. This review may result in the issuance of a negative declaration, in which case

the project may proceed in accordance with any stipulations attached to local or county permits. The review may also result in the need to complete a draft EIS.

When it is complete with the draft EIS, the lead agency distributes copies to all interested agencies. Written and oral comments on the draft EIS taken in public hearings are considered in the determination by the lead agency whether a final EIS is required.

The EIS process, however, when required may not be sufficient in itself to lead to a final permit to construct. In addition to satisfying local land use requirements of municipal/ county planning agencies, effluent discharge permits also must be obtained from state agencies. These permits are granted upon direct application to the appropriate agency.

- c. Air Pollution Discharge Permits. New air pollution sources with the potential to emit 25 tons/yr. of any regulated pollutant must be reviewed by the DHES Air Quality Bureau before construction. Within 60 days after receiving a completed application, DHES must make a final determination as to the project's conformity to air quality standards. (If an EIS is required this period is extended to 180 days).

New sources will be required to install "best available control technology" which is determined on a case-by-case basis.

Depending upon emissions potential and possible PSD review, the facility would also be subject to federal EPA regulations. The application, in any case, should be made with the DHES Air Quality Bureau to determine the procedures which must be followed. This submission should be made at least one year in advance of projected development work. The abated air emissions from the proposed project are unlikely to be subject to federal EPA permitting.

- d. Water Discharge Permit. No permit is required for the channeling of project liquid effluents to an evaporation pond if the impoundment is on private land. For surface disposal of the geothermal fluid, the DHES Water Quality Bureau must determine that the water quality is consistent with surface water quality in the general project area and will prescribe monitoring requirements, operating conditions, and compliance schedules to the approved permit. If it is clear that the geothermal effluent quality is below that required for surface disposal, a fluid injection system must be provided under state and federal (EPA) injection procedures.

e. Fresh Water Requirements. Fresh water for the plant and project would have to come from local shallow groundwater resources. Considering the relatively small amount needed for the plant (500-600 acre feet per year), it is unlikely that such a demand would place a burden upon existing supplies, except possibly in areas where water is over-appropriated. Normal state water appropriation procedures would be followed to secure this fresh water need.

H. CONCLUSIONS AND RECOMMENDATIONS

1. The Madison Valley geothermal resource, centered in the vicinity of the Ennis Hot Springs, is a very attractive prospect for exploration and development. Temperatures and expected production could readily support a number of direct heating, industrial process applications, low temperature organic Rankine cycle electric power generation and, possibly, a hybrid electric power project upon which this study has been based.
2. The projected volumes of wood waste that might be available to the project are significantly less attractive. It is doubtful that the required minimum volume (about 60,000 OD tons annually) could be purchased economically short of a procurement strategy that involved stumpage purchase.
3. There are no apparent land and geothermal resource procurement problems, environmental issues, or regulatory concerns that could not be alleviated by intelligent engineering design and proper plant operation.
4. Given the current and foreseeable power purchase environment in Montana, it is simply impossible for the type of project discussed herein to be undertaken. It is possible that some hydroelectric projects with much lower operating costs and no

fuel purchase requirements could survive with the relatively low power purchase rates available to small power producers. In view of the estimated development and operating costs of the proposed project, however, the economics of the project are far from being even marginally attractive.

5. While the project discussed herein is not economically feasible, the proposer retains an interest in helping to stimulate alternative development possibilities in the Ennis area based on the geothermal prospect alone. This project would most likely involve direct heating, a light industrial application or a combination thereof. Less certain, although still possible would be the inclusion of a small, low temperature organic Rankine cycle power plant for pumping and other in-house electrical requirements, particularly if the plant module could be purchased at the deep discounts presently being offered by certain manufacturers.

APPENDIX

DRAFT
PROJECT MILESTONE REPORT
(Milestone 4)

Prepared for

Montana Department of Natural Resources
and Conservation

by

GeoProducts Corporation

January 1984

(Grant Agreement #DE-FG79-82BP-3577G)

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Cycle I	Capital Cost Estimate Wood Fired Steam-Turbine Cycle
Cycle II	Capital Cost Estimate Wood Fired Steam-Turbine Cycle With 275°F Geothermal Heat Supplement
Cycle III	Capital Cost Estimate Wood-Fired Steam Turbine Cycle With 250°F Geothermal Heat Supplement

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1. Introduction

The purpose of this milestone is to present a number of conceptual engineering designs for a modular-sized (15 MWe design output) power plant using wood residues as the primary fuel. The 15 MWe plant size has been selected based on several years of project development experience in California by GeoProducts and represents what appears to be an optimum sized plant for most sites, both economically and from the standpoint of wood fuel supply logistics and competing uses for wood residues.

Montana, as is true of several other western states, has a rich abundance of wood fuel and moderate-to-low temperature geothermal resources. In most instances, however, the geothermal resources are of a quality (less than 350°F) not capable of economically generating electricity directly. However, used in conjunction with wood fuel resources at certain site locations, it could contribute to the overall efficiency and economics of a wood-fuel based electric power project. The results of this engineering cycle analysis then can be applicable to many sites throughout Montana where wood residues may exist within an economic haul distance of promising geothermal resource areas.

This chapter will present five conceptual power cycles and for each identify associated capital and operating costs. Plant cycle diagrams, mass and energy balances, major equipment specifications, and fuel requirements for each are also included. Costs and fuel requirements developed herein will be used later in Milestone 8 to discuss overall project economics.

2. Cycle Selection and Description

Three conceptual power cycles have been selected for comparative analysis; two of the cycles incorporate two different geothermal resource temperatures.

The base cycle is a wood-fired conventional steam turbine configuration with no geothermal contribution. The second cycle incorporates geothermal energy to preheat feedwater and combustion air for the steam cycle. The third cycle uses geothermal fluids to preheat combustion air for the steam cycle and to vaporize a working fluid in a two stage binary power cycle. An outline description of the three basic cycles analyzed is as follows:

A. Cycle I.

This base cycle (Figure 1) consists of a wood fuel fired steam boiler and steam driven turbine-generator with an induced draft cooling tower, water circulating system, feed water pumps and heaters in a five stage con-

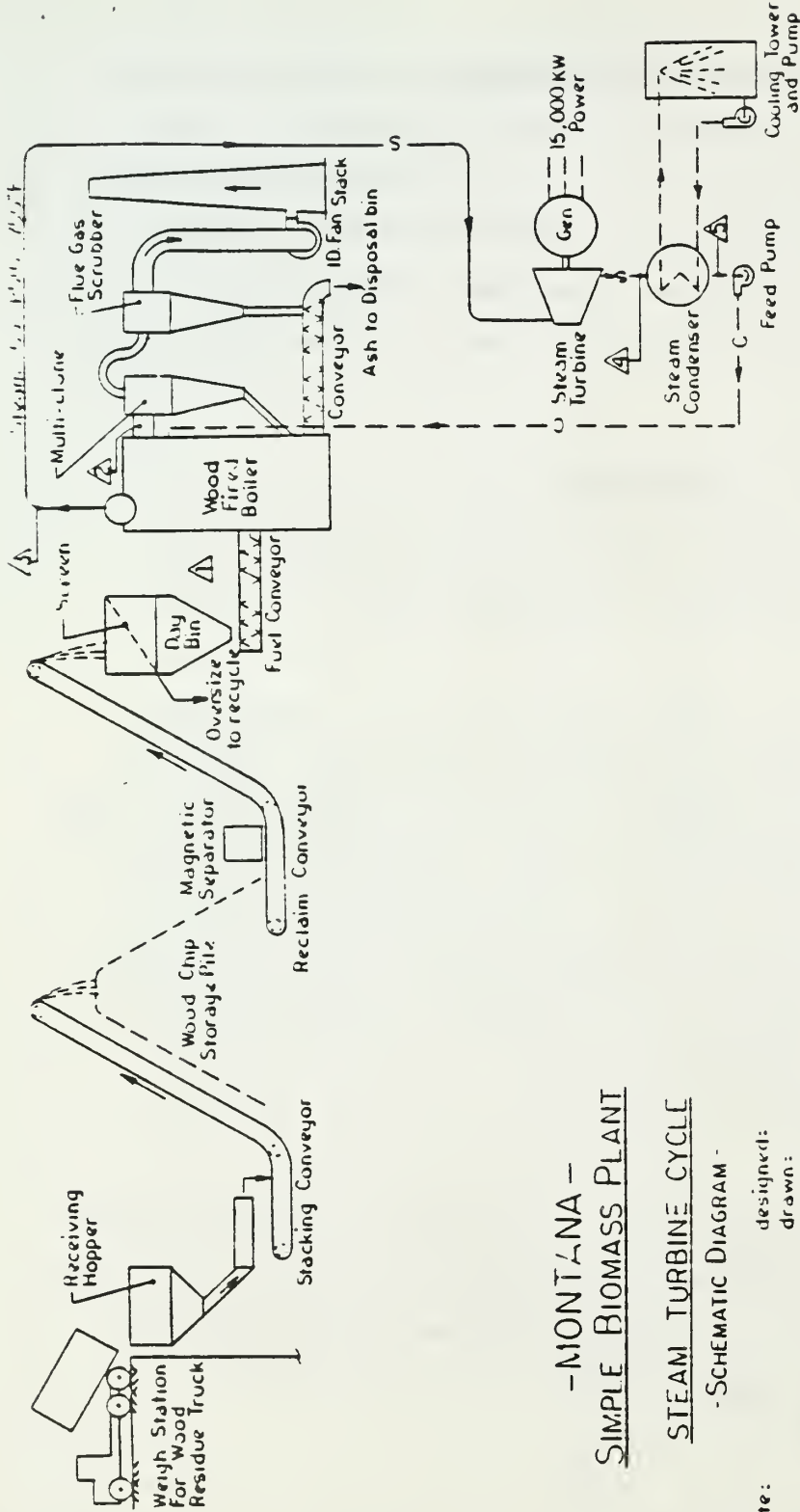


FIGURE 1

-MONTANA - SIMPLE BIOMASS PLANT

STEAM TURBINE CYCLE

-SCHEMATIC DIAGRAM -

date: _____ designed: _____
drawn: _____

STREAM NO.	1	2	3	4	5
DESCRIPTION	Plant Fuel Supply	Flue Gas	Steam Supply to Turbine	Steam Turbine Exhaust	Boiler Feed water
• Flow lbs/hr	21661	138000	98550	98550	98500
• Pressure Psig	-	-	600	1.5 HgA	70°
• Temp °F	70°	400°	825°		319.5
• Enthalpy BTU/lb	8860		1421.4		
• BTU/hr output	191x10 ⁶				
• BTU/hr input					

figuration. The wood fuel system consists of a chipper, stacker, metal separator, conveyors, screen, day storage bin, and fuel conveyor to the boiler. The operating parameters at each stage in the cycle can be identified in the table accompanying Figure 1.

The wood fuel cycle will be a direct simple system. Wood chips will be received from self dumping chip vans and payment to the supplier will be made upon a negotiated price per unit volume as received. Wood chips purchased on a weight basis are inherently to the users disadvantage because of rocks and moisture in the fuel. When buying the wood chips on a volume basis from self dumping trailers, a truck dumper, hopper and weigh station are eliminated with a capital cost savings of about \$500,000 plus elimination of 3 staff operators that would otherwise be required. Oversize chips, if any, will be hauled back by the supplier for reprocessing at his plant, so that an on site wood hogger is not required. An on site wood fuel supply of 30 days will be maintained. Wood fuel dumped on the site will be handled by a nominal 2.5 cubic yard capacity diesel front end loader which will manage the storage pile on a first in, first out basis. The operator of the loader will pile fuel near the reclaim conveyor for feeding the boilers. The fuel will pass under a magnetic separator for collecting tramp iron

from the fuel to protect the systems. Entering a covered conveyor section, the fuel is elevated to a screen section for separating out oversize particles for recycle. Acceptable size particles pass through the screen to the day storage bin. This day storage bin permits wood fuel handling operations to be limited to 8 hours per day, 7 days a week. Wood fuel leaving the day storage bin is fed by conveyor to the boiler. A fire pump and 4 yard hydrants will be available to protect the wood yard and the powerplant.

Utilizing geothermal heat to dry the wood fuel was considered and rejected because of the additional equipment needed such as a hammermill, additional chip screens, dryers with air pollution controls, and material handling sub-systems for recycling the fuel. In addition extra operating staff and maintenance expense would be required for fuel drying which is too costly and involved for this installation.

Pollution Control. Flue gas leaving the boiler will pass first through a multi-cyclone particulate separator (recycling solids to the boiler) and secondly - through a 2-stage wet gas scrubber unit for air pollution control. An induced draft 120 hp fan exhausts flue gas to the 60 foot stack. The wet gas scrubber is preferred over the

electro-static precipitator as a simpler more positive system to capture wood particulates even though the scrubber requires added fan power. Electro-static precipitator performance on wood particles is not a long proven art and the "rapping" practice to clean the unit may cause breakage.

Based on information supplied from equipment vendors, particulate air emissions from the base case wood only plant are estimated to be 24 lbs. per hour.

Emissions from hog fuel boilers are predominately particulates. Wood fuel contains little or no sulfur, and other gaseous emissions including NOX would be within EPA guidelines.

Bottom ash from the boiler grate and fly ash from the flue gas scrubber are collected and conveyed to a hopper for collection and periodic dumping of the ash into a truck container. The system will provide for off-site disposal of the ash, either as a commercial fertilizer or, if not useable, as solid waste.

Structures. The boiler and steam turbine with auxiliaries will be supported on a reinforced concrete foundation spread to reduce the soil bearing pressure. A

conservatively oversized pad of 2200 square feet and 4 feet in thickness for spreading the equipment loading has been included in the project budget. The final design of the foundations can not begin until soil borings are made and analyzed, after which, the final foundation design should permit a reduction of the pad oversize dimensions.

A pre-engineered metal building of 1600 square feet area has been estimated for enclosing the steam turbine, main panelboards, motor control and electrical auxiliaries. A similar type office and first aid building will have 1250 square feet.

The powerplant will have a cold start-up capability by the temporary burning of fuel oil in the boiler for generating electricity. A 20,000 gallon oil tank will provide a 24 hour standby capability for 4000 KW of output.

Powerplant Auxiliaries. Make-up water at about 220 GPM capacity for the plant cooling tower and boiler feedwater will be supplied from fresh water wells. A water treatment system will include chemical feeders and filtration tanks with back wash capability.

A sewage treatment system will be installed to serve the office building.

Residual chemicals in the blow-down streams from the boiler and from the cooling tower will be piped for gravity drainage to an evaporation pond. A diked earthen pond with an impervious liner will concentrate the chemical solids in the bottom of the pond. Excess water will be evaporated off while chemicals will be accumulated in the pond for the life of the project.

Six-inch water mains will be buried below the frost line around the plant perimeter and wood chip pile with 4 fire hydrants connected and guarded.

The parking lot, access road and chip van trucks turn around will be paved.

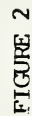
The site will include a 6 foot high cyclone fence around the plant perimeter.

B. Cycle II A.

This power cycle incorporates geothermal energy into the wood fuel steam boiler configuration described above as Cycle I. The cycle is schematically portrayed in Figure 2 with accompanying mass flow and energy data. The cycle employs two additional heat exchangers, shown in streams 8 and 9, to preheat the combustion air and boiler feedwater for the wood-fired steam cycle. This cycle has a geothermal entering fluid temperature of 275°F.

The addition of a geothermal heater for the boiler feedwater improves cycle performance because steam that is normally required to heat the condensate remains in the turbine to release its energy for power generation. This effect is reflected in a reduction in fuel requirements for a constant electrical generation. To determine the optimum size geothermal heater and outlet temperatures for final design a detailed analysis of all influential factors must be considered, which is beyond the scope of the present discussion. The emphasis here is to establish preliminary estimates for thermal and fuel advantages in relation to the use of geothermal heat.

A theoretical illustration may be used to show the effect of boiler feedwater heating over a wide range of geothermal temperatures for a plant with a nominal yearly wood fuel requirement of 365,000 OD tons without geothermal augmentation. Table 1 shows that plant heat rate improves significantly with the addition of geothermal feedwater heating, particularly as the geothermal water temperature increases. Corresponding savings in wood fuel consumed are equally significant, ranging from 2.1% at 225°F to 7.3% at 340°F geothermal fluid temperature. The percent of geothermal heat supplied ranges from 5.3% to 11.8%, depending on geothermal temperatures. These per-

[illegible]

centages are somewhat higher than the corresponding percent of fuel savings because geothermal heat is relatively low grade and cannot directly offset the fuel consumed in the same proportions as heat supplied.

Figure 3 depicts the behavior of several variables as a function of geothermal feedwater heating temperature.

As preheating boiler feedwater with geothermal energy improves cycle performance and reduces wood fuel requirements, so too does preheating the combustion air.

Geothermal air heating effectively replaces the fuel that is required to heat the air from ambient temperature to the heater exhaust temperature. Since a reduction in fuel is realized, a similar reduction in combustion air flow occurs. Consequently, the addition of heat to the air has a corresponding effect on performance improvement. Total heat supplied to a plant does not change with the addition of air heat; however fuel requirements are less since some of the heat is supplied from a geothermal source.

A theoretical example can also be used to show the effects on cycle performance and wood fuel savings attributable to using a geothermal heat source for providing combustion air preheating. The example will use the same geothermal temperature range used in the hypothetical

Table 1

PERFORMANCE GAINS FROM GEOTHERMAL FEEDWATER HEATING

Geothermal Temp., F	No Geo.			
	Heating	225	275	340
Differential Plant Heat				
Rate, Btu/KWH	Base	-284	-511	-946
Geo. Flow, Gpm	0	1127	1006	986
Geo. Heat, MM Btu/Hr	0	36.652	54.533	80.275
% Geo. Heat	0	5.3	8.0	11.8
Fuel Saved, Wet Tons/Yr	0	11,743	21,129	39,115
Fuel Saved, O.D. Tons/Yr	0	5,777	10,395	19,244
% Fuel Saved	0	2.1	3.9	7.3

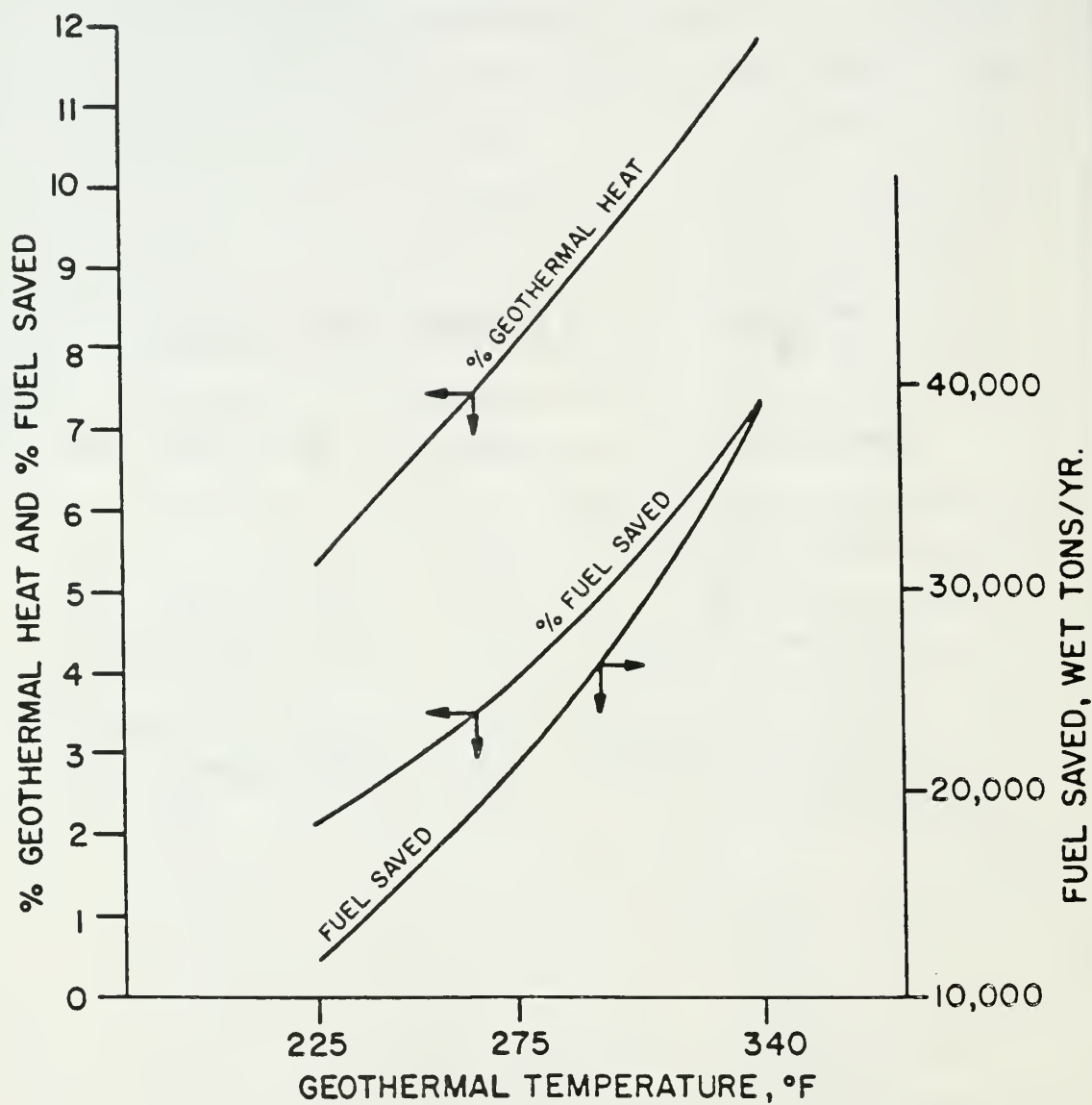


FIGURE 3
GEOTHERMAL FEEDWATER HEATING

example above to illustrate the effects of geothermal heating of boiler feedwater. The heater approach (temperature difference between entering air and exiting water) and terminal difference (temperature difference between exiting air and entering water) are selected as 50°F and 30°F respectively and are the same for each of the three alternatives examined. The effect of lowering the approach is to increase heater size and reduce geothermal water flow, while the effect of lowering the terminal difference is to increase the heat supplied to the air (since the air temperature increases) with a corresponding increase in water flow.

The relative performance comparisons between the alternate temperatures are depicted in Table 2. Fuel savings achieved by using geothermal heat can be substantial. The fuel saved, relative to the fuel required with no geothermal air heating ranges from 4.6% to 7.9% for the range of geothermal temperatures selected. Figure 4 depicts the behavior of several variables as a function of geothermal heating of combustion air.

These examples illustrate the potential cycle efficiency and fuel effects of geothermal energy augmentation of a wood-fuel power plant relative to a wide range of geothermal source temperatures. They are not meant to

Table 2

PERFORMANCE GAINS FROM GEOTHERMAL COMBUSTION AIR HEATING

Geothermal Temp., F	No Geo.			
	Heating	225	275	340
Geo. Flow, gpm	0	333	313	298
Geo. Heat, MM Btu/Hr	0	20.860	27.482	35.886
% Geo. Heat	0	3.2	4.2	5.5
Fuel Saved, Wet Tons/Yr	0	24,695	32,728	42,705
Fuel Saved, O.D. Tons/Yr	0	12,150	16,102	21,011
% Fuel Saved	0	4.6	6.1	7.9

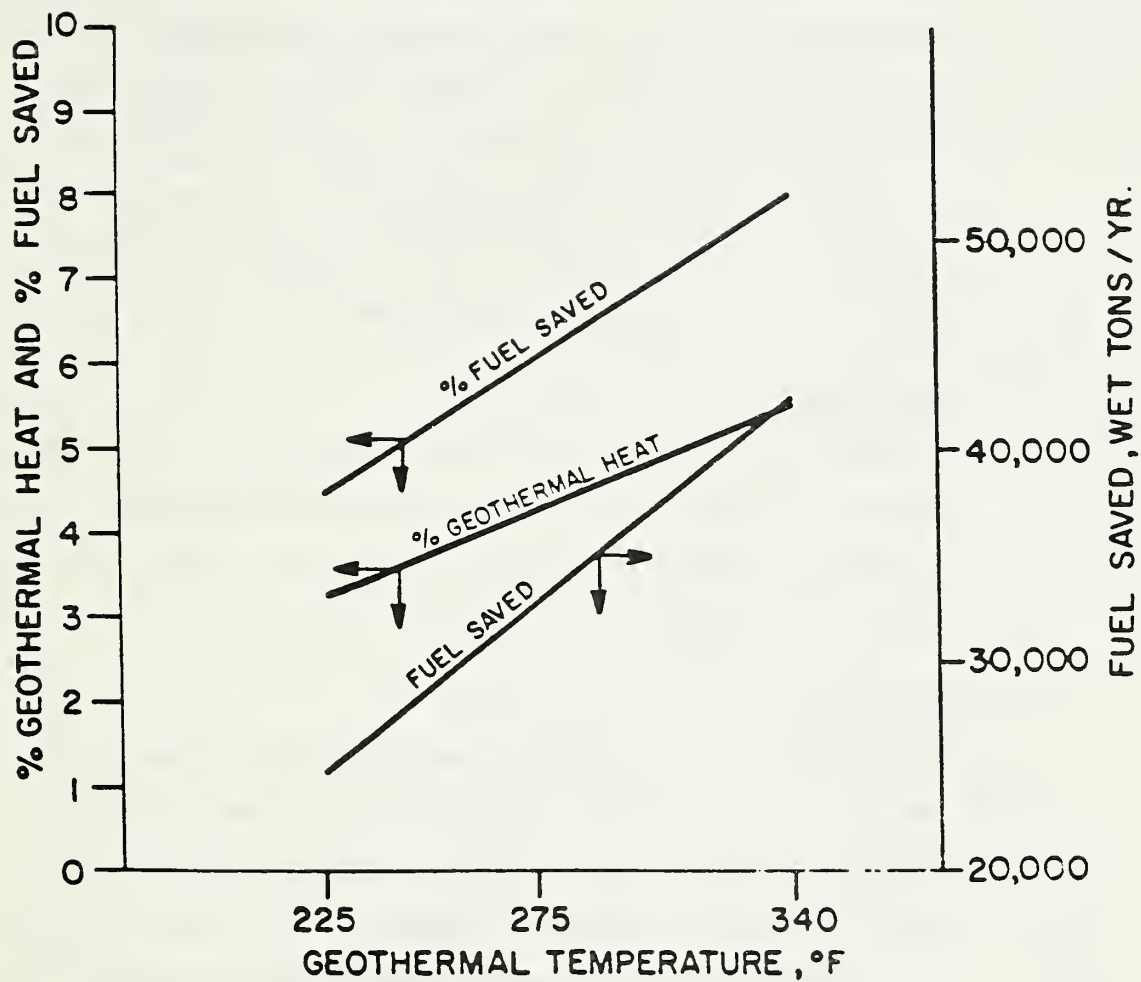


FIGURE 4
GEOTHERMAL AIR HEATING

suggest that all such effects are economically feasible. Previous work sponsored by GeoProducts on the hybrid plant concept* in fact suggests that at the lower temperatures used in the above examples, geothermal augmentation systems cannot be economically justified. As geothermal source temperatures increase, however, using geothermal energy to augment feedwater and combustion air heating can promote significant efficiencies in cycle performance and wood fuel requirements.

C. Cycle II-B.

This cycle is the same as cycle II-A employing geothermal energy to heat combustion air and boiler feedwater, except the temperature of the geothermal fluid is cooler, at 250°F.

D. Cycle III-A.

This cycle also employs geothermal energy to heat combustion air for the wood-fired steam boiler (but not boiler feedwater) which produces 4000 Kw power output. More importantly, however, the geothermal fluids are used in a binary power cycle with its own turbine generator to contribute electric power (11,000 Kw output) developed

* "Honey Lake Hybrid Power Plant: Engineering and Economic Study Report", 1982.

from low-temperature heat. The geothermal source temperature is 275°F. Figure 5 shows the power cycle schematic and accompanying energy and mass flow data.

This low temperature power generation loop will use a binary working fluid (such as isobutane or isopentane) in a Rankine cycle which includes two stages of binary vaporizers, a gas expansion turbine, a water cooled binary condenser, and a condensate feed pump for pressurizing and returning fluid to the two vaporizers. A heat recovery heat exchanger within the binary loop may be added (not shown), depending upon the superheat in the binary exhaust.

The first stage binary vaporizer is heated by entering low temperature geothermal fluids (250 - 275°F). The second stage binary vaporizer is heated by entering superheated exhaust steam (about 335°F) which is condensed at a saturated condition of 57.5 psia and 290°F. The binary condenser is cooled by water circulated from a cooling tower. The binary cycle net efficiency is estimated to be about 15%.

The steam turbine generator selected produces 4512 Kw (gross) and 4164 Kw (net). Wood chips from the day storage bin are fed to a conventional wood-fired traveling grate or pin-hole grate steam boiler having a

basic efficiency of 68 percent with 45 percent moisture fuel. Wood gasifiers with waste heat boilers were investigated and rejected because efficiencies offered were only 60 to 62 percent and capital costs were higher. The combustion air will be preheated by geothermal fluid, which will reduce the wood fuel requirement. The geothermal-air heat exchanger is mounted in a duct on the discharge side of the boiler forced draft fan. The boiler will have an automatic control system to control the firing rate in response to steam demand.

Steam conditions of 600 PSIG and 740°F were selected to match the operating conditions for the Elliott back-pressure steam turbine selected. At 42.5 PSIG back pressure, the Elliott unit has an approximate turbine efficiency of 76 percent. Steam exhaust from the turbine has a modest amount of superheat, which is removed along with the heat of condensation in the second stage isobutane heater described above. The steam is condensed in the second stage isobutane heater and is pumped, under pressure and with 290°F, back to the boiler in a closed cycle.

Powerplant Electrical Systems. Main power will be generated at 4160 volts, 60 Hertz at the binary and the steam driven turbine generators. Both generators will

have static exciters. The binary driven generator will be totally enclosed and fan cooled to guard against leakage of the binary working fluid. All other electrical machinery and equipment will be explosion proof or will be separated by minimal NEMA code distances from the binary system.

The powerplant will include main generator circuit breakers, switchyard, bus ducts, turbine generator control panel boards, grounding mat, cable trays, transformer for 480 volt station service, motor control centers for auxiliary motors, plant instrumentation, conduit and wiring, yard lighting, plant lighting and an in-house intercomm with 6 remote stations and six hand sets.

The main powerplant transformer will be provided by the power purchaser.

The two plant cycles are relatively simple and direct:

- a. there are a minimum of boiler feedwater heaters
- b. the back pressure steam turbine does not require air ejectors or condensers
- c. the condensate pumps serve as feed pumps
- d. the schematic diagram is no more complex than that required for a single-resource plant with ease of operation and reliability
- e. the overall plant efficiency from the topping-bottoming cycles is good
- f. some flexibility in operations can be achieved by varying geothermal fluid flow and wood fuel input.

E. Cycle III-B.

This cycle also incorporates a geothermal binary loop with a wood-fired steam boiler as in Cycle III-A, except the geothermal resource temperature is 250°F.

3. Wood Fuel Requirements Summary

To note the effect on wood fuel consumption of incorporating geothermal energy into the basic wood-fired steam cycle, the following wood fuel requirements summary is provided (units are in oven dry tons):

	<u>lb/Hr</u>	<u>Tons/Hr</u>	<u>Tons/Yr</u> <u>(85% CF)</u>	<u>Savings</u>
Cycle I	21,661	10.8	80,417	-
Heating Cycle II-A (275°F)	18,071	9.0	67,014	17%
Heating Cycle II-B (250°F)	18,459	9.2	68,503	15%
Binary Cycle III-A (275°F)	15,281	7.6	56,590	30%
Binary Cycle III-B (250°F)	15,754	7.9	58,823	27%

4. Capital Costs

Preliminary plant capital costs are summarized in Table 3. Detailed lists and specifications are provided in Appendix A. Unit prices are based on vendor quotations, R.S. Means and Company estimating manual and previous work conducted on similar facilities by International Engineering Company and GeoProducts Corporation. All dollars are as of September 1983.

Table 3

CAPITAL COST SUMMARY

(\$000's 1984)

	Cycle I	Cycle II-A	Cycle II-B	Cycle III-A	Cycle III-B
Direct Investment					
Wood System	9554.00	9047.76	9071.74	6132.41	6131.41
Binary System	-	-	-	11770.00	11770.00
Geothermal System	-	<u>1362.20</u>	<u>1362.20</u>	<u>1362.20</u>	<u>1362.20</u>
Total Direct	8554.00	10409.96	10433.94	19264.61	19264.61
Indirect Investment					
Sales Tax (6%)	573.24	624.60	626.04	1177.48	1177.48
Performance Bond (1.2%)	114.65	124.92	125.21	235.50	235.50
Construction Permit (2.0%)	191.00	208.20	208.68	392.49	392.49
Construction Income (.7%)	66.88	72.87	73.04	137.37	137.37
Contractor's Mobilization (12%)	1146.48	1249.20	1252.07	2354.95	2354.95
Engineering Fee (8%)	764.32	832.80	834.72	1569.97	1569.97
Construction Management Fee (3%)	<u>286.62</u>	<u>312.30</u>	<u>313.02</u>	<u>588.74</u>	<u>588.74</u>
Total Indirects	3143.19	3424.89	3432.78	6456.50	6456.50
Total Plant & Equipment	12697.19	13834.85	13866.72	25721.11	25721.11
Land (40 Acres @ \$1000/Ac.)	<u>40.00</u>	<u>40.00</u>	<u>40.00</u>	<u>40.00</u>	<u>40.00</u>
Total Installed Cost	<u>12737.19</u>	<u>13874.85</u>	<u>13906.72</u>	<u>25761.11</u>	<u>25761.11</u>

5. Plant Operating Requirements

The staff required to operate and maintain the proposed facility is developed based on the plant operating philosophy and a review of existing facilities with similar equipment and capacity. Adjustments are made to the staff to cover variations resulting from the geothermal equipment.

Brief descriptions of the scope of responsibility as well as a typical salary for each position on the chart are included.

The plant operating requirements are based on the following assumptions:

- ° The plant operates as a base load generating facility at design load on a continuous basis, except when shut down for the following reasons:

planned annual outage	3 weeks
forced outages	2 weeks
maintenance outages	2 weeks

- ° The plant operating staff works on a rotating shift basis to support a seven day per week, 24-hour plant operation. The staff rotates from shift to shift so that each person spends an equal amount of time on each shift over a one year period. The schedule for shift periods is left to the manager's discretion.

- ° The plant administration and maintenance staff work on a day shift basis, Monday through Friday. Should additional maintenance work be required, it can be accomplished by the maintenance staff on an overtime or call-in overtime basis or, if required, by contract crews.
- ° Annual maintenance on a unit of this size and type typically requires about three weeks and includes a boiler overhaul and minor turbine inspection.
- ° The plant staff performs plant maintenance and operations only. Other functions, such as contracting for fuel and scheduling the fuel deliveries are accomplished by others. To have this function performed by plant staff would require an additional position.
- ° Salaries for plant personnel are predicated on typical contacts with electric utilities.

Plant Staff

Plant Manager

The Plant Manager is the senior man at the site. His responsibilities include direct supervision of the Supervisor of Plant Operations and the Plant Engineer and

indirect supervision of all plant personnel. He has responsibility for all personnel, plant staff and contractors involved in work activities at the site.

Other items over which the plant manager has direct control are scheduling, budget, purchasing, compliance with government regulation, public relations, and implementation of plant safety programs.

Plant Engineer

The Plant Engineer is responsible for plant maintenance. He develops and implements preventative maintenance programs, sets up a spare parts inventory and provides technical support for resolution of all plant design and maintenance problems.

Plant Equipment Operator

The Plant Equipment Operator reports to and accepts direction from the Control Operator. They perform the actual hands-on operation of equipment in the plant. They monitor and record equipment operating data and plant information as required.

Fuel Equipment Operator

The Fuel Equipment Operator reports to and accepts direction to the Plant Manager. He performs the actual hands-on operation of the fuel handling system. This system encompasses all the wood receiving and handling system equipment up to the interface with the boiler.

Journeyman Craftsmen (Mechanic, Electrician,
Instrumentation and Controls Technician)

Each craft performs maintenance and repair work on equipment within its jurisdiction. They maintain all plant equipment in good working order.

The following table reflects the position, annual salary, number of employees per position and other operating costs estimated for each cycle.

Table 4

OPERATING COST SUMMARY

		Cycle I	Cycle II-A	Cycle II-B	Cycle III-A	Cycle III-B
	(000's)					
Direct Labor Summary	\$ Year					
Plant Manager	36.00	1.00	1.00	1.00	1.00	1.00
Plant Operator	30.00	6.00	6.00	6.00	7.00	7.00
Wood Yard Men	27.00	3.00	3.00	3.00	3.00	3.00
Maintenance	24.00	2.00	3.00	3.00	3.00	3.00
Clerk-Receptionist	15.00	1.00	1.00	1.00	1.00	1.00
Direct Labor		360.00	384.00	384.00	414.00	414.00
Burden	<u>.45</u>	<u>162.00</u>	<u>172.80</u>	<u>172.80</u>	<u>186.30</u>	<u>186.30</u>
Sub-Total labor & burden		522.00	556.80	556.80	600.30	600.30
Operation & Maint. (\$000's)		182.40	202.40	202.40	312.80	312.80
Insurance (\$000's) (1%)		127.37	138.75	139.07	257.61	257.61
Taxes (\$000's) (1%)		127.37	138.75	139.07	257.61	257.61
Wood Fuel (ODT/Hr)		10.80	9.00	9.20	7.60	7.90
Geothermal Heat (kw)						

APPENDICIES

CYCLE I

CAPITAL COST ESTIMATE

WOOD FIRED STEAM-TURBINE CYCLE

<u>ITEM</u>	<u>COSTS IN</u> <u>1943 IN</u> <u>\$000's</u>
1. Wood fired steam boiler, 600 Psig, 825°F, 98,500 lbs/hr., with traveling grate, economizer; structural steel, air heater, forced draft fan, combustion controls, breeching and connections, no stack, flue gas multiclone included but not the gas scrubber, efficiency of 71% burning 43% moisture content fuel, Riley Stoker Co. data	2947.0
2. Flue gas scrubbers, 2 each 12 ft. diameter, 2 stage with one 200 Hp I.D. fan, Sly N: 212	235.0
3. Stack, 60 inch diameter x 60 feet high steel \$330/ft x 60 ft.	19.8
4. Make up water treatment system 3262 bhp x \$2.054/Hp (Means)	6.7
5. Boiler feedwater pumps: 2 each, 200 gpm each, 750 psig disch press, 75% pump eff., 75 Hp each (means) \$303/Hp x 75 Hp x 2 each	45.4
6. Deaerator 98550 lbs./hr (Dodge)	83.7
7. Feedwater heaters, 2nd, 3rd, 4th stage units, total of 4977 square feet required at \$3080 x 39 units	120.3
8. Steam piping 8 inch main, 120 lin. ft. boiler to turbine, 10 inch 50 psi extraction steam run to feed water heaters, 250 lin. ft. all on spring type hangers (means) 8 in. @ 120 lin. ft. x \$90/lin. ft. 10 in. @ 250 lin. ft. x \$135.6/lin. ft.	10.8 33.9
9. Condensate piping from condenser and feedwater heaters to boiler, 5 inch, 160 linear feet x 48.13	7.7

10.	Cooling water piping 18 inch pvc x 550 lin. ft. x \$102/lin. feet	56.1
11.	Steam-turbine generator with speed increaser, and exciter, 15000 Kw gross capacity, 600 psig inlet throttle and 1.5 inches Hg Vac. exhaust, with condenser, and auxilliaries \$266/kw x 15000 kw	3988.0
12.	Wood fuel conveyor (8.6 dry tons/ 1 - .43) = 12.8 net wet tons/ hr. x 2 for surge cap. = 25.6 tons/hr rated capacity, 30 inch belt. 7.5 hp drive with trough idlers and channel frame: \$264.44/lin. ft. x 180 lin. ft. x 2 sections (1 section for wood stacking and 1 for reclaim)	95.2
13.	Conveyor structural supports \$12,500 x 2 sections	25.0
14.	Wood fuel day storage bin 12.8 net wet tons/hr consumption x 24 hour capacity x 2000 x 1/18 ft. ³ /lb. = 68,266 ft. ³ steel bin equals a 500,000 gal. tank x .31/gal.	155.2
15.	Oil storage for standby fuel supply 35,000 gal. oil, steel, buried, coated (means) \$10,491 x 1.12 x 2	23.5
16.	Oil pump set with oil burners/standby	8.0
17.	Steam and condensate pumping insulation 8 inch, 120 lin. ft. \$23.83 10 inch, 250 lin. ft. \$28.98 5 inch 160 lin ft. \$12.23/ft.	2.9 7.2 1.9
18.	Steam and condensate valves 8 inch 600 lb. \$4121 10 inch 150 lb. \$2512 5 inch 800 lb. \$3026 4 inch 800 lb. \$2834	8.2 19.9 24.0 16.9
19.	Wood fuel screen $\$19500 / 75 \text{ tons/hr.} \times \frac{25.8 \text{ T}}{75 \text{ T}} \times \frac{1}{.6} \times 1.15$	12.8
20.	Magnetic separator on wood conveyor	8.7
21.	Fire pump 500 gpm, elect	10.5
22.	Motor control center for boiler FD fans, ID fans, feed pumps, circ. pumps, fire pumps, condensate pumps, 12 motor controller each @ 15 hp avg. \$776 x 12 x 1.15 with enclosure	9.3

23.	Breeching insulation: 60' x TY x 5' = 942 ft. ² 942/ft. ² x 12.82/ft. ²	12.0
24.	Boiler/turbine control board	22.0
25.	Electrical conduit, wiring, fixtures	100.0
26.	Fencing around powerplant and yard: 500 lin. ft., 6 ft. high at \$11.80/ft. x 1.12	7.6
27.	Foundation pad for boiler and Turb-Gen 35 ft. x 70 ft. x 4 ft. thick = 363 Cu. yard x \$201.00	72.4
28.	Enclosure for control room, plant office, with toilets and first aid station: 20 ft. x 50 ft. = 1000 sq. ft. x \$52.68/sq. ft.	52.3
29.	Ash handling system, screw conv. and slurry piping	48.0
30.	Evaporation pond for disposal of boiler blowdown and cooling tower	40.0
31.	Enclosure for turbine generator; 50 ft. x 25 ft. x \$38.57/sq. ft.	47.8
32.	Make up water main 6 inch 600 lin. ft. at 7.5/ft.	4.5
33.	Sewage treatment unit/office 1500 gallon, \$6144	6.1
34.	Cooling tower, 10,177 gpm cooled from 94 F to 74 F with 67 F wet bulb air (equivalent to 6785 tons capacity) 6.785 units x \$61662/unit	418.5
35.	Cooling water pumps 10,177 each, 2 required, 70 ft. head, 75% eff., 250 hp each x \$188.04/hp x 2	46.7
36.	Condensate pumps: 197 gpm x 240 ft. head, 75% eff., 20 hp each, 2 required, 20 hp x \$303/hp x 2 each	12.0
37.	Communication system 2 stations x 4 stations: \$1649	1.6
38.	Station service transformer and switches	50.4
39.	Fire hydrants: 4 each at \$1107	4.4
40.	Paving 7000 square ft. 3 inch asphalt \$13.524/sq. ft.	94.1

41.	Bus duct	40.1
42.	High volt switchgear, gen. breaker panel, cable tray, high voltage feeders, grounding, instrumentation (high voltage transformers not included since by public utility company) 252.8 x 2.17 x .7	<u>489.9</u>
	TOTAL CAPITAL COST	<u><u>\$9554.0</u></u>

CYCLE II-A

CAPITAL COST ESTIMATE

WOOD FIRED STEAM-TURBINE CYCLE
WITH 275°F GEOTHERMAL HEAT SUPPLEMENT

<u>ITEM</u>	<u>COSTS IN</u> <u>1984 IN</u> <u>\$ 000's</u>
1. Wood fired steam boiler, 600 Psig, 825°F, 98,500 lbs/hr., with traveling grate, economizer; structural steel, air heater, forced draft fan, combustion controls, breeching and connections, no stack, flue gas multiclone included but not the gas scrubber, efficiency of 71% burning 43% moisture content fuel, Riley Stoker Co. data	2452.5
2. Flue gas scrubbers, 2 each 12 ft. diameter, 2 stage with one 200 Hp I.D. fan, Sly N: 212	195.09
3. Stack, 60 inch diameter x 60 feet high steel \$330/ft x 60 ft.	16.44
4. Make up water treatment system 3262 bhp x \$2.054/Hp (Means)	5.56
5. Boiler feedwater pumps: 2 each, 200 gpm each, 750 psig disch press, 75% pump eff., 75 Hp each (means) \$303/Hp x 75 Hp x 2 each	37.69
6. Deaerator 98550 lbs./hr (Dodge)	69.49
7. Feedwater heaters, 2nd, 3rd, 4th stage units, total of 4977 square feet required at \$3080 x 39 units	171.2
8. Air preheater a. 15 coils @ \$1600 each + \$3600 labor b. Breaching air ducts c. 10 hp Fan @ \$350/hp	27.6 11.0 3.5
9. Steam piping 8 inch main, 120 lin. ft. boiler to turbine, 10 inch 50 psi extraction steam run to feed water heaters, 250 lin. ft. all on spring type hangers (means) 8 in. @ 120 lin. ft. x \$90/lin. ft. 10 in. @ 250 lin. ft. x 135.6/lin. ft.	10.8 33.9

10.	Condensate piping from condensers and feed water heaters to boiler, 5 inch, 160 lin. feet x \$48.13/lin. ft.	7.7
11.	Cooling water piping 18 inch pvc x 550 lin. ft. x \$102/lin. feet	56.1
12.	Steam-turbine generator with speed increaser, and exciter, 15000 Kw gross capacity, 600 psig inlet throttle and 1.5 inches Hg Vac. exhaust, with condenser, and auxiliaries \$266/kw x 15000 kw	3988.0
13.	Wood fuel conveyor (8.6 dry tons/ 1 - .43) = 12.8 net wet tons/ hr. x 2 for surge cap. = 25.6 tons/hr rated capacity, 30 inch belt. 7.5 hp drive with trough idlers and channel frame: \$264.44/lin. ft. x 180 lin. ft. x 2 sections (1 section for wood stacking and 1 for reclaim)	79.04
14.	Conveyor structural supports \$12,500 x 2 sections	19.78
15.	Wood fuel day storage bin 12.8 net wet tons/hr consumption x 24 hour capacity x 2000 x 1/18 ft. ³ /lb. = 68,266 ft. ³ steel bin equals a 500,000 gal. tank x .31/gal.	128.85
16.	Oil storage for standby fuel supply 35,000 gal. oil, steel, buried, coated (means) \$10,491 x 1.12 x 2	23.5
17.	Oil pump set with oil burners/standby	8.0
18.	Steam and condensate pumping insulation 8 inch, 120 lin. ft. \$23.83 10 inch, 250 lin. ft. \$28.98 5 inch 160 lin ft. \$12.23/ft.	2.9 7.2 1.9
19.	Steam and condensate valves 8 inch 600 lb. \$4121 10 inch 150 lb. \$2512 5 inch 800 lb. \$3026 4 inch 800 lb. \$2834	8.2 19.9 34.19 23.76
20.	Wood fuel screen $\$19500 / 75 \text{ tons/hr.} \times \frac{25.8 \text{ T}}{75} \times \frac{1}{.6} \times 1.15$	10.63
21.	Magnetic separator on wood conveyor	7.22
22.	Fire pump 500 gpm, elect	10.5

23.	Motor control center for boiler FD fans, ID fans, feed pumps, circ. pumps, fire pumps, condensate pumps, 12 motor controller each @ 15 hp avg. \$776 x 12 x 1.15 with enclosure	9.3
24.	Breeching insulation: 60' x TY x 5' = 942 ft. ² 942/ft. ² x 12.82/ft. ²	9.96
25.	Boiler/turbine control board	22.0
26.	Electrical conduit, wiring, fixtures	100.0
27.	Fencing around powerplant and yard: 500 lin. ft., 6 ft. high at \$11.80/ft. x 1.12	7.6
28.	Foundation pad for boiler and Turb-Gen 35 ft. x 70 ft. x 4 ft. thick = 363 Cu. yard x \$201.00	72.4
29.	Enclosure for control room, plant office, with toilets and first aid station: 20 ft. x 50 ft. = 1000 sq. ft. x \$52.68/sq. ft.	52.3
30.	Ash handling system, screw conv. and slurry piping	48.0
31.	Evaporation pond for disposal of boiler blowdown and cooling tower	40.0
32.	Enclosure for turbine generator; 50 ft. x 25 ft. x \$38.57/sq. ft.	47.8
33.	Make up water main 6 inch 600 lin. ft. at 7.5/ft.	4.5
34.	Sewage treatment unit/office 1500 gallon, \$6144	6.1
35.	Cooling tower, 10,177 gpm cooled from 94 F to 74 F with 67 F wet bulb air (equivalent to 6785 tons capacity) 6.785 units x \$61662/unit	418.5
36.	Cooling water pumps 10,177 each, 2 required, 70 ft. head, 75% eff., 250 hp each x \$188.04/hp x 2	46.7
37.	Condensate pumps: 197 gpm x 240 ft. head, 75% eff., 20 hp each, 2 required, 20 hp x \$303/hp x 2 each	9.96
38.	Communication system 2 stations x 4 stations: \$1649	1.6
39.	Station service transformer and switches	50.4

40.	Fire hydrants: 4 each at \$1107	4.4
41.	Paving 7000 square ft. 3 inch asphalt \$13.524/sq. ft.	94.1
42.	Bus duct	40.1
43.	High volt switchgear, gen. breaker panel, cable tray, high voltage feeders, grounding, instrumentation (high voltage transformers not included since by public utility company) 252.8 x 2.17 x .7	489.9
44.	Sub-total wood fired boiler, steam turbine generator power plant Items 1 through 42	9,047.76
45.	5000 ft. production well, with wellhead assembly	1000.0
46.	2500 - 3000 ft. injection well	250.0
47.	Production well pump (55 Hp, 500 gpm 300' total head multi-stage vertical down hole	35.0
48.	Injection well pump (split-case centrifugal, 100 psi, 500 gpm, 50 Hp	5.0
49.	Production flowline: 1000 ft., buried 8" cement asbestos, with insulation and vapor barrier	24.0
50.	Injection flowline: 1000 ft., buried 8" cement asbestos with no insulation	19.0
51.	Flowline insulation @ \$4/ft.	8.0
52.	Motor starter and circuit breaker	2.5
53.	Contingency (20% on non-well items)	18.7
54.	Total geothermal capital cost	1,362.2*
	TOTAL CAPITAL COST	\$10,409.96

*Includes both flow lines

CYCLE II-B

CAPITAL COST ESTIMATE

WOOD FIRED STEAM-TURBINE CYCLE
WITH 275°F GEOTHERMAL HEAT SUPPLEMENT

ITEM	COSTS IN 1984 IN \$ 000's
1. Wood fired steam boiler, 600 Psig, 825°F, 98,500 lbs/hr., with traveling grate, economizer; structural steel, air heater, forced draft fan, combustion controls, breeching and connections, no stack, flue gas multiclone included but not the gas scrubber, efficiency of 71% burning 43% moisture content fuel, Riley Stoker Co. data	2511.4
2. Flue gas scrubbers, 2 each 12 ft. diameter, 2 stage with one 200 Hp I.D. fan, Sly N: 212	200.27
3. Stack, 60 inch diameter x 60 feet high steel \$330/ft x 60 ft.	16.11
4. Make up water treatment system 3262 bhp x \$2.054/Hp (Means)	5.71
5. Boiler feedwater pumps: 2 each, 200 gpm each, 750 psig disch press, 75% pump eff., 75 Hp each (means) \$303/Hp x 75 Hp x 2 each	38.69
6. Deaerator 98550 lbs./hr (Dodge)	71.33
7. Feedwater heaters, 2nd, 3rd, 4th stage units, total of 4977 square feet required at \$3080 x 39 units	120.3
8. Air preheater a. 15 coils @ \$1600 each + \$3600 labor b. Breaching air ducts c. 10 hp Fan @ \$350/hp	27.6 11.0 3.5
9. Steam piping 8 inch main, 120 lin. ft. boiler to turbine, 10 inch 50 psi extraction steam run to feed water heaters, 250 lin. ft. all on spring type hangers (means) 8 in. @ 120 lin. ft. x \$90/lin. ft. 10 in. @ 250 lin. ft. x 135.6/lin. ft.	10.8 33.9

10.	Condensate piping from condensers and feed water heaters to boiler, 5 inch, 160 lin. feet x \$48.13/lin. ft.	7.7
11.	Cooling water piping 18 inch pvc x 550 lin. ft. x \$102/lin. feet	56.1
12.	Steam-turbine generator with speed increaser, and exciter, 15000 Kw gross capacity, 600 psig inlet throttle and 1.5 inches Hg Vac. exhaust, with condenser, and auxilliaries \$266/kw x 15000 kw	3988.0
13.	Wood fuel conveyor (8.6 dry tons/ 1 - .43) = 12.8 net wet tons/ hr. x 2 for surge cap. = 25.6 tons/hr rated capacity, 30 inch belt. 7.5 hp drive with trough idlers and channel frame: \$264.44/lin. ft. x 180 lin. ft. x 2 sections (1 section for wood stacking and 1 for reclaim)	81.13
14.	Conveyor structural supports \$12,500 x 2 sections	21.31
15.	Wood fuel day storage bin 12.8 net wet tons/hr consumption x 24 hour capacity x 2000 x 1/18 ft. ³ /lb. = 68,266 ft. ³ steel bin equals a 500,000 gal. tank x .31/gal.	132.26
16.	Oil storage for standby fuel supply 35,000 gal. oil, steel, buried, coated (means) \$10,491 x 1.12 x 2	23.5
17.	Oil pump set with oil burners/standby	8.0
18.	Steam and condensate pumping insulation 8 inch, 120 lin. ft. \$23.83 10 inch, 250 lin. ft. \$28.98 5 inch 160 lin ft. \$12.23/ft.	2.9 7.2 1.9
19.	Steam and condensate valves 8 inch 600 lb. \$4121 10 inch 150 lb. \$2512 5 inch 800 lb. \$3026 4 inch 800 lb. \$2834	8.2 19.9 34.19 23.76
20.	Wood fuel screen \$19500 / 75 tons/hr. x $\frac{25.8}{75} \frac{T}{T}$ x $\frac{1}{.6}$ x 1.15	10.91
21.	Magnetic separator on wood conveyor	7.41
22.	Fire pump 500 gpm, elect	10.5

23.	Motor control center for boiler FD fans, ID fans, feed pumps, circ. pumps, fire pumps, condensate pumps, 12 motor controller each @ 15 hp avg. \$776 x 12 x 1.15 with enclosure	9.3
24.	Breeching insulation: 60' x TY x 5' = 942 ft. ² 942/ft. ² x 12.82/ft. ²	10.23
25.	Boiler/turbine control board	22.0
26.	Electrical conduit, wiring, fixtures	100.0
27.	Fencing around powerplant and yard: 500 lin. ft., 6 ft. high at \$11.80/ft. x 1.12	7.6
28.	Foundation pad for boiler and Turb-Gen 35 ft. x 70 ft. x 4 ft. thick = 363 Cu. yard x \$201.00	72.4
29.	Enclosure for control room, plant office, with toilets and first aid station: 20 ft. x 50 ft. = 1000 sq. ft. x \$52.68/sq. ft.	52.3
30.	Ash handling system, screw conv. and slurry piping	48.0
31.	Evaporation pond for disposal of boiler blowdown and cooling tower	40.0
32.	Enclosure for turbine generator; 50 ft. x 25 ft. x \$38.57/sq. ft.	47.8
33.	Make up water main 6 inch 600 lin. ft. at 7.5/ft.	4.5
34.	Sewage treatment unit/office 1500 gallon, \$6144	6.1
35.	Cooling tower, 10,177 gpm cooled from 94 F to 74 F with 67 F wet bulb air (equivalent to 6785 tons capacity) 6.785 units x \$61662/unit	418.5
36.	Cooling water pumps 10,177 each, 2 required, 70 ft. head, 75% eff., 250 hp each x \$188.04/hp x 2	46.7
37.	Condensate pumps: 197 gpm x 240 ft. head, 75% eff., 20 hp each, 2 required, 20 hp x \$303/hp x 2 each	10.23
38.	Communication system 2 stations x 4 stations: \$1649	1.6
39.	Station service transformer and switches	50.4

40.	Fire hydrants: 4 each at \$1107	4.4
41.	Paving 7000 square ft. 3 inch asphalt \$13.524/sq. ft.	94.1
42.	Bus duct	40.1
43.	High volt switchgear, gen. breaker panel, cable tray, high voltage feeders, grounding, instrumentation (high voltage transformers not included since by public utility company) 252.8 x 2.17 x .7	489.9
44.	Sub-total wood fired boiler, steam turbine generator power plant Items 1 through 42	9,071.74
45.	5000 ft. production well, with wellhead assembly	1000.0
46.	2500 - 3000 ft. injection well	250.0
47.	Production well pump (55 Hp, 500 gpm 300' total head multi-stage vertical down hole	35.0
48.	Injection well pump (split-case centrifugal, 100 psi, 500 gpm, 50 Hp	5.0
49.	Production flowline: 1000 ft., buried 8" cement asbestos, with insulation and vapor barrier	24.0
50.	Injection flowline: 1000 ft., buried 8" cement asbestos with no insulation	19.0
51.	Flowline insulation @ \$4/ft.	8.0
52.	Motor starter and circuit breaker	2.5
53.	Contingency (20% on non-well items)	18.7
54.	Total geothermal capital cost	1,362.2*
	TOTAL CAPITAL COST	\$10,433.94

*Includes both flow lines

CYCLE III-A

CAPITAL COST ESTIMATE

WOOD-FIRED STEAM TURBINE CYCLE
WITH 275°F GEOTHERMAL HEAT SUPPLEMENT

<u>ITEM</u>	<u>COSTS IN</u> <u>1984 IN</u> <u>\$ 000's</u>
1. Wood fired steam boiler, 600 Psig, 750°F, 124,000 lbs/hr., with traveling grate, economizer, structural steel, forced draft fan, combustion controls, breeching and connections, no stack, multiclone included but not scrubber, efficiency of 71% burning 43% moisture content fuel, Riley Stoker Boiler or equal	2604.0
2. Flue gas 2 stage water jet scrubber, 12 ft. diameter, with 200 Hp I.D. fan, all carbon steel	235.0
3. Stack, 60 inch diameter x 60 feet high galvanized	19.8
4. Make up water treatment system 3880 boiler HP	7.81
5. Boiler feedwater pumps: 2 each @ 174 gpm, 750 psig disch. press., 80% pump eff., 100 Hp motors	62.5
6. Deaerator, 124,000 lbs./hr	94.0
7. Geothermal combustion air preheater 140,000 lbs. air/hr heated from 70°F average to 255°F with 136 gpm geothermal at 275°F in and 165°F out	42.1
8. Steam piping: 8 inch main, 600 psi 100 lin. ft., boiler to turbine, 12 inch 50 psi, turbine exhaust run to binary second stage vaporizer, 50 lin. ft. Sch 80 welded, on hangers	10.8
9. Steam turbine generator with exciter, Speed increaser, 4215 Kw gross (3890 Kw system net capacity) 600 psig in, 42.5 psig out, Elliott turbine and Electric Machinery Co. generator, or equals	1057.0

10.	Wood fuel conveyor, 13 net wet tons per hour net, 26 tons/hr. max. rated capacity 150 lin. ft., 20 deg incline, covered, 30 inch belt, 7.5 HP drive, channel frame, support legs not included, trough idlers. McWorkman/Webster Mfg. Co. or equal, 2 sections	95.2
11.	Conveyor Structural support and installation	25.0
12.	Wood fuel day storage bin 68,000 cubic ft., 500,000 gal. capacity, steel	155.0
13.	Oil storage tank for standby capability, 24 hour capacity oil storage tanks = 20,000 gal/oil fuel, steel, coated, buried	23.5
14.	Oil pump set with oil burners/standby	8.0
15.	Steam and condensate pumping insulation 8 inch, 120 lin. ft. 18.55 x 1.12 x 1.15 10 inch, 250 lin. ft. 22.5 x 1.12 x 1.15 5 inch 160 lin ft. 9.5 x 1.12 x 1.15	2.9 7.2 1.9
16.	Steam and condensate piping insulation 8 inch 500 lb. \$3200 x 1.12 x 1.15 x 2 each 10 inch 150 lb. \$1950 x 1.12 x 1.15 x 8 each 5 inch 800 lb. \$2350 x 1.12 x 1.15 x 8 each 4 inch 800 lb. \$2200 x 1.12 x 1.15 x 6 each	8.2 19.9 24.0 16.9
17.	Wood fuel screen $\$19500 / 75 \text{ tons/hr.} \times \frac{25.8 \text{ T}}{75} \times \frac{1}{.6} \times 1.15$	12.8
18.	Magnetic separator on wood conveyor	8.7
19.	Fire pump, 500 gpm, elect drive	10.5
20.	Motor control center for boiler FD fans, ID fans, feed pumps, circ. pumps, fire pumps, condensate pumps, 12 motor controller each @ 15 hp avg. \$675 x 12 x 1.15 with enclosure	9.3
21.	Breeching insulation: 60' x TY x 5' = 942 ft. x 1.12 x 1.15 x \$9.95/ft.	12.0
22.	Boiler/turbine control board	22.0
23.	Electrical conduit, wiring, fixtures	100.0
24.	Fencing around powerplant and yard: 500 lin. ft., 6 ft. high at \$11.80/ft. x 1.12	7.6

25.	Foundation pad for boiler and Turb-Gen 35 ft. x 70 ft. x 4 ft. thick = 363 Cu. yard x \$155.9 x 1.12 x 1.15	72.4
26.	Enclosure for control room, plant office, with toilets and first aid station: 20 ft. x 50 ft. = 1000 sq. ft. x \$40.9/sq. ft. x 1.12 x 1.15	52.3
27.	Ash handling system, screw conv. and slurry piping	48.0
28.	Evaporation pond for disposal of boiler blowdown and cooling tower	40.0
29.	Enclosure for turbine generator; 50 ft. x 25 ft. x \$29.9/sq. ft.. x 1.12 x 1.15	47.8
30.	Make up water main 6 inch 600 lin. ft. at 5.9 x 1.12 x 1.15	4.5
31.	Sewage treatment unit/office 1500 gallon, \$4770 x 1.12 x 1.15	6.1
32.	Cooling tower, 10,177 gpm cooled from 94°F to 74°F with 67°F wet bulb air (equivalent to 6785 tons capacity) 6.785 units x \$47,874 x 1.12 x 1.15	418.5
33.	Cooling water pumps 10,177 each, 2 required, 70 ft. head, 75% eff., 250 hp each x \$146/hp x 2 x 1.12 x 1.15	46.7
34.	Condensate pumps: 197 gpm x 240 ft. head, 75% eff., 20 hp each, 2 required, 20 hp x \$235/hp x 2 each x 1.12 x 1.15	12.0
35.	Communication system, 2 stations x 4 stations: \$1280 x 1.12 x 1.15	1.6
36.	Station service transformer and switches	50.4
37.	Fire hydrants: 4 each at \$860 x 1.12 x 1.15	4.4
38.	Paving 7000 square ft. 3 inch asphalt \$10.5/sq. ft. x 1.12 x 1.15	94.1
39.	Bus duct	40.1
40.	High volt switchgear, gen. breaker panel, cable tray, high voltage feeders, grounding, instrumentation (high voltage transformers not included since by public utility company) 251.8 x 2.17 x .7 x 1.12 x 1.15	489.9

41. Sub-total wood fired boiler, steam turbine generator power plant
Items 1 through 42

6,132.41

42. Binary Plant

The binary plant fabricated in modules with all inter-connecting piping to and from each module and from the cooling tower. This unit includes all instrumentation and valving and the following:

- a. Wellhead separator module consisting of a solid separator manufactured by Peerless or equal and including piping to the resource
- b. Vaporizer module consisting of four Shell and Tube Heat Exchangers
- c. Economizer module consisting of two Shell and Tube Heat Exchangers operating in parallel
- d. Condenser module consisting of Shell and Tube Heat Exchangers. Two units connected in parallel TEMA type AES

- e. Expander generator module consisting of:

The Turbo-Expander manufactured by Mafi-Trench Corporation, model E-6GB complete with guide vane control

Speed Decreasing gear manufactured by Lufkin or equal with Thomas couplings

Generator manufactured by Westinghouse or equal 12 Mw 1200 RPM-4160 volt totally enclosed, water to air cooled generator complete with brushless excitation

Lube and Seal Oil System complete with the pumps, filters, reservoirs

Piping and Valving including the expander by-pass valve, expander inlet valve, the exhaust butterfly valve, check valve and associated piping

- f. Isobutane storage and nitrogen system module consists of a 24,000 gallon isobutane storage system complete with a 1,500 gallon - 250 PSIZ nitrogen storage system

g. Control module enclosure to house and include the plant control centers system, the generator switch gear, auxiliary module control and the synchronize panel. The housing is weather protected totally enclosed with dehumidified and air conditioning

h. Fire protection and instrument air module

43. Sub-Total Binary System	<u>11,770.00</u>
44. 5000 ft. production well, with wellhead assembly	1000.0
45. 2500 - 3000 ft. injection well	250.0
46. Production well pump (55 Hp, 500 gpm 300' total head multi-stage vertical down hole	35.0
47. Injection well pump (split-case centrifugal, 100 psi, 500 gpm, 50 Hp	5.0
48. Production flowline: 1000 ft., buried 8" cement asbestos, with insulation and vapor barrier	24.0
49. Injection flowline: 1000 ft., buried 8" cement asbestos with no insulation	19.0
50. Flowline insulation @ \$4/ft.	8.0
51. Motor starter and circuit breaker	2.5
52. Contingency (20% on non-well items)	18.7
53. Total geothermal capital cost	<u>1,362.2*</u>
TOTAL CAPITAL COST	<u><u>\$19,264.61</u></u>

*Includes both flow lines

CYCLE III-B

CAPITAL COST ESTIMATE

WOOD-FIRED STEAM TURBINE CYCLE
WITH 250°F GEOTHERMAL HEAT SUPPLEMENT

<u>ITEM</u>	<u>COSTS IN</u> <u>1984 IN</u> <u>\$ 000's</u>
1. Wood fired steam boiler, 600 Psig, 750°F, 124,000 lbs/hr., with traveling grate, economizer, structural steel, forced draft fan, combustion controls, breeching and connections, no stack, multiclone included but not scrubber, efficiency of 71% burning 43% moisture content fuel, Riley Stoker Boiler or equal	2604.0
2. Flue gas 2 stage water jet scrubber, 12 ft. diameter, with 200 Hp I.D. fan, all carbon steel	235.0
3. Stack, 60 inch diameter x 60 feet high galvanized	19.8
4. Make up water treatment system 3880 boiler HP	7.81
5. Boiler feedwater pumps: 2 each @ 174 gpm, 750 psig disch. press., 80% pump eff., 100 Hp motors	62.5
6. Deaerator, 124,000 lbs./hr	94.0
7. Geothermal combustion air preheater 140,000 lbs. air/hr heated from 70°F average to 255°F with 136 gpm geothermal at 275°F in and 165°F out	42.1
8. Steam piping: 8 inch main, 600 psi 100 lin. ft., boiler to turbine, 12 inch 50 psi, turbine exhaust run to binary second stage vaporizer, 50 lin. ft. Sch 80 welded, on hangers	10.8
9. Steam turbine generator with exciter, Speed increaser, 4215 Kw gross (3890 Kw system net capacity) 600 psig in, 42.5 psig out, Elliott turbine and Electric Machinery Co. generator, or equals	1057.0

10.	Wood fuel conveyor, 13 net wet tons per hour net, 26 tons/hr. max. rated capacity 150 lin. ft., 20 deg incline, covered, 30 inch belt, 7.5 HP drive, channel frame, support legs not included, trough idlers. McWorkman/Webster Mfg. Co. or equal, 2 sections	95.2
11.	Conveyor Structural support and installation	25.0
12.	Wood fuel day storage bin 68,000 cubic ft., 500,000 gal. capacity, steel	155.0
13.	Oil storage tank for standby capability, 24 hour capacity oil storage tanks = 20,000 gal/oil fuel, steel, coated, buried	23.5
14.	Oil pump set with oil burners/standby	8.0
15.	Steam and condensate pumping insulation 8 inch, 120 lin. ft. 18.55 x 1.12 x 1.15 10 inch, 250 lin. ft. 22.5 x 1.12 x 1.15 5 inch 160 lin ft. 9.5 x 1.12 x 1.15	2.9 7.2 1.9
16.	Steam and condensate piping insulation 8 inch 500 lb. \$3200 x 1.12 x 1.15 x 2 each 10 inch 150 lb. \$1950 x 1.12 x 1.15 x 8 each 5 inch 800 lb. \$2350 x 1.12 x 1.15 x 8 each 4 inch 800 lb. \$2200 x 1.12 x 1.15 x 6 each	8.2 19.9 24.0 16.9
17.	Wood fuel screen \$19500 / 75 tons/hr. x $\frac{25.8 \text{ T}}{75 \text{ T}}$ x $\frac{1}{.6}$ x 1.15	12.8
18.	Magnetic separator on wood conveyor	3.7
19.	Fire pump, 500 gpm, elect drive	10.5
20.	Motor control center for boiler FD fans, ID fans, feed pumps, circ. pumps, fire pumps, condensate pumps, 12 motor controller each @ 15 hp avg. \$675 x 12 x 1.15 with enclosure	9.3
21.	Breeching insulation: 60' x TY x 5' = 942 ft. x 1.12 x 1.15 x \$9.95/ft.	12.0
22.	Boiler/turbine control board	22.0
23.	Electrical conduit, wiring, fixtures	100.0
24.	Fencing around powerplant and yard: 500 lin. ft., 6 ft. high at \$11.80/ft. x 1.12	7.6

25.	Foundation pad for boiler and Turb-Gen 35 ft. x 70 ft. x 4 ft. thick = 363 Cu. yard x \$155.9 x 1.12 x 1.15	72.4
26.	Enclosure for control room, plant office, with toilets and first aid station: 20 ft. x 50 ft. = 1000 sq. ft. x \$40.9/sq. ft. x 1.12 x 1.15	52.3
27.	Ash handling system, screw conv. and slurry piping	48.0
28.	Evaporation pond for disposal of boiler blowdown and cooling tower	40.0
29.	Enclosure for turbine generator; 50 ft. x 25 ft. x \$29.9/sq. ft.. x 1.12 x 1.15	47.8
30.	Make up water main 6 inch 600 lin. ft. at 5.9 x 1.12 x 1.15	4.5
31.	Sewage treatment unit/office 1500 gallon, \$4770 x 1.12 x 1.15	6.1
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